STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	Case No. U-17990

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on December 16, 2016.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before January 9, 2017, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before January 18, 2017. **The Commission has selected this case for participation in its Paperless Electronic Filings Program. No paper documents will be required to be filed in this case.**

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Dennis W. Mack

Dennis W. Mack
Administrative Law Judge

December 16, 2016
Lansing, Michigan

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STATE OF MICHIGAN

MICHIGAN ADMINISTRATIVE HEARING SYSTEM

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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PROPOSAL FOR DECISION

I.

HISTORY OF THE PROCEEDINGS

On March 1, 2016, Consumers Energy Company (Company) filed an application with the Michigan Public Service Commission (Commission) seeking to increase its retail electric base rates $225 million from the rates approved in its previous rate case.[1] The application also seeks other authorizations including ratemaking adjustment mechanisms, revisions to electric rules, regulations and tariffs, and accounting measures. In response to the application, the Commission's Executive Secretary issued a Notice of Hearing on March 9, 2016.

[1] Those rates were set in a November 19, 2015 Order of the Commission in Case No. U-17735.

A pre-hearing conference was held on April 12, 2016, where the Company and Staff appeared. On that date, the Appearances were entered by, and intervention was granted to:

1. Hemlock Semiconductor Operations LLC, f/k/a Hemlock Semiconductor Corporation, (Hemlock);
2. Michigan Cable Telecommunications Association (MCTA);
3. Natural Resource Defense Council (NRDC)/Michigan Environmental Council (MEC)/Sierra Club (SC);
4. Association of Businesses Advocating Tariff Equity (ABATE);
5. Residential Customer Group (RCG) & Michele Rison;
6. Michigan State Utility Workers Council & Utility Workers of America, AFL-CIO;
7. Midland Cogeneration Venture Limited Partnership;
8. ChargePoint, Inc.;
9. Energy Michigan, Inc.;
10. The Attorney General;
11. The Kroger Company (Kroger).

See 1 TR 17-18, 30-31, 62.

A petition to intervene filed by Phil Forner, along with a request for a declaratory ruling, was denied. Id., at 17, 41.[2] The petitions to intervene filed by the Environmental Law and Policy Center, Wal-Mart Stores East, LP, and Sam's East, Inc. (Wal-Mart), were granted subsequent to the pre-hearing. See 1 TR 69-70; Dkt. # 67 & 76. During the

[2] On May 20, 2016, the Commission affirmed the denial of Mr. Forner's petition to intervene. Dkt. # 95. On May 24, 2016, Mr. Forner filed a Petition for Rehearing, which the Commission denied on July 22, 2016. Dkt. # 185. On August 11, 2016, Mr. Forner filed a Claim of Appeal in the Court of Appeals. Dkt. #238.

pre-hearing, William Malcolm, Senior Legislative Representative – State Advocacy and Strategy, for AARP, Inc., entered comments under R 792.10413. 1 TR 10-13.

The schedule established during the pre-hearing conference included a process for the Commission's consideration of the self-implementation of the Company's proposed rate increase. See MCL 460.6a(1). The evidentiary hearing for self-implementation was held on July 27, 2016, at which time the Company entered the testimony of Michael A. Torrey, Vice President Rates and Regulation, and Exhibits SI-1 and SI-2. Mr. Torrey testified the Company intended to self-implement $170 million on September 1, 2016. 3 TR 120.[3] On August 3, 2016, the Company filed a Brief in Support of Self-Implementation. None of the other parties offered any evidence or filed a brief on the issue. The record was transmitted to the Commission, which did not issue an Order preventing or delaying self-implementation, resulting in the increase taking effect on the 180th day after the Application was filed, September 1, 2016. MCL 460.6a(1).

The hearing in this matter was conducted on September 7, 8, 9, 12, and 13, 2016.[4] During the hearing the Company offered the testimony of the following employees:

1. Garrick Rochow, Vice President and Chief Customer Officer – Customer Experience, Rates & Regulation, and Quality (Direct);

2. Josnelly C. Aponte, Senior Rate Analyst, Rate Analysis and Administration Section of the Rates and Regulation Department (Direct and Rebuttal);

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[3] Exhibit SI-1 sets forth the Interim Rate Increase, Subject to Refund, for each Rate Class, while Exhibit SI-2 details the Interim Surcharges based on an equal percent rate design that produces the $170 million.

[4] After hearing argument on September 7, the Company's Motion to Strike portions of the Direct Testimony of Sebastian Coppola, and two exhibits submitted with that testimony, was granted. 4 TR 145-153. Two other Motions to Strike filed by the Company, along with a Motion to Strike filed by the Attorney General, were denied. Id., 153-169.

3. Andrew J. Bordine, Director of Customer Management and Grid Infrastructure (Direct, Supplemental and Rebuttal);

4. Rachel L. Brege, Senior Rate Analyst III in the Rates and Regulatory Affairs Department (Direct and Rebuttal);

5. Heather A. Breining, Senior Engineering Technical Analyst II (Direct and Rebuttal);

6. Eugene M.J.A. Breuring, Senior Rate Analysts II, Planning, Budgeting & Analysis Section of the Rates and Regulation and Quality Department (Direct, Supplemental and Rebuttal);

7. Laura M. Collins, Principal Rate Analyst, Pricing Section of the Rates Department (Direct and Rebuttal);

8. Amy M. Conrad, Director of Compensation (Direct and Rebuttal);

9. Andrew J. Denato, Director of Financial Analysis and Forecasting (Direct and Rebuttal);

10. Daniel L. Harry, Director of Accounting Process and Control (Direct, Supplemental and Rebuttal);

11. Lisa A. Hesche, Corporate Tax Manager, Tax Department (Direct);

12. David B. Kehoe, Executive Director of Staff, Energy Resources Business Services (Direct and Rebuttal);

13. Herbert P. Kops, Director of Employee Benefits (Direct and Rebuttal);

14. Jeffrey C. Mayes, Director of Economic Development Strategy (Direct and Rebuttal);

15. Julio H. Morales, Executive Director of Customer Services (Direct and Rebuttal);

16. Dhenuvakonda (“DV”) Rao, Vice President of Financial Planning and Treasurer (Direct and Rebuttal);

17. Anne K. Rogus, Director of Revenue Requirements and Analysis (Direct, Supplemental and Rebuttal);

18. David F. Ronk, Jr., Executive Director of Electric Transactions and Wholesale Settlements (Direct and Rebuttal);

19. John E. Sherman, Supply Operations Superintendent, Energy Supply Department (Direct);

20. R. Michael Stuart, Utility Metrics Director (Direct and Rebuttal);

21. Scott D. Thomas, Executive Director of Asset Management and Engineering (Rebuttal that also serves to adopt the Direct testimony and Exhibit of Brian J. Fitzgerald);

22. Michael A. Torrey, Executive Director – Rates and Regulatory Affairs in the Customer Experience, Rates and Regulation and Quality Department (Direct and Rebuttal);

23. Brian J. VanBlarcum, Property Tax Manager, Corporate Tax Department (Direct);

24. Christopher J. Varvatos, Executive Director of Business Technology for Distribution Operations & Engineering and Transmission (Direct and Rebuttal);

25. Lincoln D. Warriner, Financial Benchmarking Analyst in the Economic Portfolio Management Section of the Distribution Operations, Engineering, and Transmission Department (Direct and Rebuttal).

Through these witnesses, the Company entered Exhibits A-1 through A-24, inclusive, A-26 through 46, inclusive, A-48 through A-85, inclusive, A-87 through A-103, inclusive, A-106 through A-120, inclusive, and A-122 and A-123.[5]

During the hearing the other Parties entered the following testimony and exhibits:

1. Attorney General: Sebastian Coppola, independent business consultant (Direct and Rebuttal); and Exhibits AG-1 through AG-29, inclusive.

2. ABATE:

- Stephan M. Rackers; Consultant with Brubaker & Associates, Inc.;
- Christopher C. Walters, Consultant with Brubaker & Associates, Inc. (Direct and Rebuttal);
- Nicholas Phillips, Jr., Managing Principal, Brubaker & Associates (Direct and Rebuttal); and
- Exhibits AB-1 through AB-24, inclusive.

3. Energy Michigan: Alexander Zakem, a Consultant for matters involving Merchant Energy and Utility Regulation; and Exhibits EM-1, EM-2, and EM-3.

[5] Exhibits A-25 and A-47 were not offered, Exhibit A-85 was entered as Exhibit A-121, and Exhibits A-104 and A-105 were not admitted.

4. ChargePoint: James Ellis, Director of Utility Solutions for ChargePoint, Inc. (Direct and Rebuttal).

5. Hemlock: Michael Gorman, Managing Principal of Brubaker & Associates, Inc.; and Exhibits HSC-1 through HSC-14, inclusive.

6. Wal-Mart: Steve Chriss, Senior Manager, Energy Regulatory Analysis, Wal-Mart Stores, Inc.; and Exhibits SWC-1, SWC-2, SWC-3, and SWC-4.

7. Kroger: Neal Townsend, Principal, Energy Strategies, LLC; and Exhibits NT-1 and NT-2.

8. NRDC: Ralph Cavanagh, Co-Director, Energy Program, Natural Resources Defense Council; and Exhibit NRDC-1.

9. Sierra Club/NRDC/Environmental Law & Policy Center/MEC: Douglas B. Jester, Principal of 5 Lakes Energy LLC (Direct and Rebuttal); and Exhibits SC-1 through SC-9, inclusive.

10. MEC: George E. Sansoucy, George Sansoucy, P.E., LLC; and Exhibits MEC-19 through MEC-26, inclusive.

11. MEC/NRDC/Sierra Club: Dan F. Koehler, Consultant at Daymark Energy Advisors Inc.; and Exhibits ME-1 through MEC-18, inclusive. Through cross-examination of various witnesses, MEC-27 through MEC-54. Inclusive.

12. Staff:
    - Lauren Fromm, Public Utilities Engineer, Smart Grid Section, Operations and Wholesale Markets Division;
    - Ryan Laruwe, Engineer, Electric Operations, Operations and Wholesale Markets Division;
    - Mark J. Pung, Departmental Analyst, Rates and Tariffs Section, Regulated Energy Division;
    - Charles Putman, Departmental Analyst, Rates and Tariffs Section, Regulated Energy Division;
    - Nicholas M. Revere, Manager of the Rates and Tariffs Section, Regulated Energy Division (Direct and Rebuttal);
    - Jill Rusnak, Public Utilities Engineer, Act 304 and Sales Forecasting Section, Regulated Energy Division;

- Jay Gerken, Auditor, Revenue Requirements Section, Financial Analysis and Audit Division;
- Kirk Megginson, Financial Specialist, Revenue Requirements Section, Financial Analysis and Audit Division;
- Robert F. Nichols II, C.P.A., Managers, Revenue Requirements Section, Financial Analysis and Audit Division;
- Robert G. Ozar. P.E., Assistant Director, Electric Reliability Division;
- Nicholas M. Evans, Public Utilities Engineer, Generation and Certificate of Need Section, Electric Reliability Division; and
- Exhibits S-1, S-2, S-3, S-4, and S-6 through S-39, inclusive.

A Protective Order was entered on June 7, 2016, after a Motion to Compel Discovery pertaining to that Order was argued and decided on June 6, 2016. Dkt. # 108 and 2 TR 74-105. Under that Protective Order, certain of the testimony and exhibits of the Parties were deemed confidential and entered under a separate record.

Consistent with the schedule established during the pre-hearing conference, Initial Briefs and Reply Briefs were filed. [6]

In order to ensure compliance with the statutorily imposed timeframe for deciding this case, MCL 460.6a(3), the evidence and arguments necessary for a reasoned analysis of the disputed issues are expressly addressed in the Proposal for Decision. However, all of the evidence presented in this case, and the arguments made by the parties based on that evidence, was considered.

[6] All of the Parties except the MCTA, Michigan State Utility Workers Council & Utility Workers of America, AFL-CIO, Midland Cogeneration Venture Limited Partnership, and the Environmental Law and Policy Center filed Initial Briefs. Reply Briefs were filed by the Company, Hemlock, ABATE, ChargePoint, and Staff.

II. THE COMPANY'S APPLICATION

The Company is an investor-owned utility that provides electric energy to approximately 1.8 million retail customers in Michigan. As such, its retail electric business, including its rates, are subject to the Commission's regulation under various statutes. See MCL 460.1, *et seq*., MCL 460.540, *et seq*., and 460.551, *et seq*. Under this authority, the Company's application seeks Commission approval to increases its electric rates $225 million from those set in Case No. U-17335. Subsequently, Consumers reduced the increase it is seeking in this proceeding to $208 million. Initial Brief, Appendix A, Dkt. #362. That amount represents the electric revenue deficiency the Company claims will result under its current rates based on a projected Test Year of September 1, 2016 to August 31, 2017. The application attributes these deficiencies primarily to investments in system reliability, of which 72% of the rate increase will be applied, along with costs associated with environmental compliance and technology. Other factors identified in the application include increased costs for the Company's Smart/Grid/Advanced Metering Infrastructure project, financing, and reduced sales margin resulting from a decrease in demand. Also included in the proposed rates is an authorized return on common equity of not less than 10.70%, and an overall rate of return on total base rate of 6.27%.

The Company is also seeking to recover revenue requirements for two programs it will offer during the Test Year. The first, termed the Demand Response Program, will allow business customers to contract for load reduction during peak periods in return for compensation for the released capacity. The revenue requirements for this program is estimated at $2.9 million. The second entails installation of Plug-In Electric Vehicle infrastructure in its service area for areas with high-traffic, but little or no charging access, at a cost of $1.3 million.

The Company proposes to set its rates for each of its rate classes under cost-of-service principles. To that end, the proposed rate design allocates production capacity using a 4 coincident peak and a 100% demand allocator and updates the intersystem sales allocator from capacity to an energy allocator. The Company also proposes various revisions to its rules, regulations, tariffs governing electric sales, and accounting changes, including those associated with the ratemaking adjustment mechanisms offered in the Application.

In general, the Company seeks authorization to increase its retail electric rates in order to provide $208 million annually, including a Return on Equity (ROE) of not less than 10.70%, above its established rates based on a projected test year ending on August 31, 2017. The Company proposes authorization of two ratemaking adjustment mechanisms. The first is a Revenue Adjustment Mechanism, conditioned on enactment of legislation addressing such a mechanism during the pendency of this case, to reconcile any variance between nonfuel rate revenues approved by the Commission and actually generated. The second is an Investment Recovery Mechanism (IRM) that would recover capital investments, beyond those incorporated in rates up to August 31, 2017, for specified programs set forth in an annual plan and recovered in a subsequent reconciliation proceeding.

III. TEST YEAR

The Company is basing its requested increase on projected costs and revenues for a 12-month test year ending August 31, 2017. See MCL 460.6a(1). Those projections derived from actual costs and revenues in 2014, and then adjusted for updated sales figures, and projected investments, expenses, and revenues. No party has objected to the test year, and thus it should be adopted.

IV. RATE BASE

"Rate base consists of total utility plant (i.e., the capital invested in all plant in service, plant held for future use, and construction work in progress (CWIP)), less the company's depreciation reserve (consisting of its accumulated depreciation, amortization, and depletion), plus the utility's working capital requirements." *In Re Application of Consumers Energy Co., to Increase Rates*, Case No. U-17735, November 19, 2015 Order, pg. 7. In this case, the Company projects its rate base for the test year at $10.293 billion. See Exhibit A-6, Schedule A-1. That amount consists of $9.494 billion in net plant, $827.487 million in working capital requirements, with a reduction of $28.857 million in retainers and customer advances. As noted, approximately $161 million of the rate increase will go to investment related costs for generation supply and distribution system reliability, environmental compliance, and technology upgrades. See 5 TR 651-662. The components of the rate base projected by the Company, and reductions proposed by Staff and the Intervenors are as follows:

A. Net Plant Utility

1. Electric Distribution and Energy Supply Capital Expenditures

Mr. Bordine testified the Company is requesting rate recognition of capital expenditures for electric distribution of $374,790,000 in 2014 (actual), $387,492,000 in 2015 (preliminary), $469,320,000 in 2016, $310,816,000 for the eight months ending

August 31, 2017, $179,020,000 for the four months ending December 31, 2017, $493,878,000 in 2018, and 489,577,000 in 2019. 6 TR 1125; Exhibit A-16.[7] These amounts will be invested in nine major programs that Mr. Bordine testified to in detail: (1) New Business; (2) Reliability; (3) Grid Modernization; (4) Capacity; (5) Demand Failures; (6) Asset Relocations; (7) Electric Operations Other; (8) HVD-T; and (9) Electric Business Services." 6 TR 1126-1145. The purpose of the expenditures are to meet projections for new business, customer reliability expectations, system infrastructure improvements for expected load, replace assets in response to emergent demand failures, relocate electric distribution infrastructure, and for fleet/facility upgrades. 6 TR 1126.

Staff takes issue with the test year projection for 3 programs. The first is Reliability, which Staff contends should be adjusted downward $3,532,000 because the amount projected in the test year in the Company's last rate case, U-17735, was "significantly over-projected" when compared actual spending. 8 TR 2577. In response to Staff inquiries about the variation, the Company indicated Reliability program expenditures are pro-active, as opposed to other programs that are reactive to customer requests, and thus year-to-year spending fluctuations. While Staff understands the nature of the program may lead to fluctuations, the Company failed in its obligation to show the "significant overruns existed in the test year and that these overruns were prudently incurred in the reactive programs." Id., 2578. Absent such a showing, Mr. Laruwe testified the Company failed to account for the significant underspending, and "the most recent 12 months actual are more representative of a reasonable

[7] Starting in 2016, the expenditures are projected amounts.

spending plan and is recommending a test year budget equal to the U-17735 preliminary spend of $84,758,000." Id.

Mr. Laruwe also indicated that 65% of the spending in this program in 2015 was for the replacement of distribution poles, but the Company failed to establish pole failures significantly contribute to reliability issues. Further, the Company has replaced 7,283 poles in 2015 under the Demand Failure program, which is not mentioned in this case. Finally, Mr. Laruwe took issue with the Company's over-all approach to pole replacement:

> The Company states it does not utilize any remedial efforts for low voltage distribution (LVD) poles which is contrary to industry best practices and potentially leads to unnecessary cost increases to both the Reliability and Demand Failure programs. Industry research has clearly shown that remediation can provide significant incremental benefit and is a more cost effective long term strategy for addressing distribution poles. [footnote omitted]. Staff recommends the Company investigate the potential remediation of poles and provide a cost benefit analysis justifying why replacement is preferred to remediation. This investigation should also provide insight into pole failure rates and causes of pole failures in the service territory.
> 8 TR 2579

In response, the Company contends that U-17735 was approved halfway through the rate year, and the amount for this program that was ultimately approved was less than was requested, rendering it difficult to meet the approved expenditure level. The Company also argues Mr. Laruwe relied on incomplete data to reach his conclusion regarding under-spending, and the data that was ultimately provided to him showed increased spending. Along the same lines, the Company contends Mr. Laruwe did not account for all spending for the time-frame he reviewed, and misstated the amount of spending for pole replacement in the Reliability program. 6 TR 1157. The Company also argues the report relied on for Mr. Laruwe's recommendation regarding remediation is unreliable, and if it were required would result in substantial Operation & Maintenance (O&M) expenses for the 1,500,000 poles in its distribution system. Id., 1160.

Based on Mr. Bordine's testimony, the underspending in the Reliability program is understandable given the timing of the decision in Case No. U-17335. Further, utility pole failures are a significant issue in reliability with 17% of interruptions attributable to equipment failure, including poles. Further, a pole remediation program would also entail expenses borne by the ratepayers that Mr. Laruwe did not factor into his conclusion. Accordingly, Staff's recommended downward adjustment of the test year projection for the Reliability program should not be adopted, nor should a pole remediation program be required. Rather, Staff and the Company should, as the Company suggests, discuss a pole remediation program outside the confines of a rate case.

Staff's next adjustment is to the Capacity Capital program, which the Company projected at $56.275 million for the test year. Mr. Laruwe testified the program had an actual expenditure of $45,690,000, while the level approved in U-17735 was $58,617,000, a difference he termed significant. Mr. Laruwe indicated Staff's concerns regarding both the underspending and the program itself:

> [T]he Company describes its strategic capital allocation which has led to the deferral of Capacity Program spending in the past, leading to a significant backlog of projects. Staff attempted to examine the backlog of projects as well as the modeling that allows the Company to delay projects multiple years without detrimental impacts on reliability in audit response #33 (Exhibit S9.7 (RSL-8)). The Company provided a list of projects and modeling results that show overloads but no information that led Staff to believe these projects are past the conceptual stage and unlikely to be

> deferred. Furthermore, the audit response explained that the Company will not know the 2017 Capacity projects until the fourth quarter of 2016. This is of concern as approximately 67% of the projected test year of this case occurs in 2017. Intervenors in this case will not have the ability to review any 2017 projects which will constitute a majority of the spending in the test year as they will not be available until well after the filing date in this case.
> 8 TR 2580

Based on the lack of evidence regarding the spending for his program, along with the underspending, Mr. Laruwe recommends the preliminary spend in U-17735, $45,690,000, be adopted in this case. The Company counters this argument by indicating it is committed to projects in this program and is undertaking "a robust modeling methodology that utilizes the most current data…" to select projects. 6 TR 1162. While it is not possible to quantify the Company's commitment to the program, the fact that approximately $13,000,000 was not spent, along with the inability to review the 2017 projects that are ultimately selected through the "robust modeling" is concerning. Given that the Company has not provided the information necessary to determine the projected test amount is warranted, Staff's adjustment of the Capacity program should be accepted, and the amount set at $45,690,000.

Staff's final adjustment is to the Grid Modernization program projected spending plan of $69,219,000. As with the other two items, Mr. Laruwe determined the Company had a significant variation from the $30,334,000 spent for Grid Modernization approved in U-17735, to preliminary test year spending of $15,214,000. 8 TR 2581. Again, Staff found the Company unresponsive to its inquiries about the basis for the underspending and what improvements would be undertaken to with the increased funding. Mr. Laruwe testified this information "is necessary in order to review the prudency of the projected spending plans and key in holding the Company accountable when auditing spending in general rate cases." Id., 2582. Given the importance of components of this program, such as deployment of the Distribution Supervisory Control and Data Acquisition in LVD substations to provide real-time monitoring equipment control, Staff recommends a test year budget of $40,000,000, which is an increase over the U-17735 test year budget. Staff also recommends the Company be directed to file a Grid Modernization report that sets forth the cost/benefits of projects in this spending plan through 2019, along with pilot results for advanced grid applications in anticipation of the eventual large scale deployment. Id., 2582-2583.

In response to Staff's proposed downward adjustment to the Grid Modernization program the Company contends it provided, through the testimony of Mr. Bordine and responses to audit requests, specific information on the projects funded through the program along with the benefits that will result from the expenditures. 6 TR 1131-1135; Exhibits A-78, 79 and 80. A fair reading of the testimony indicates it sets forth, in detail, the benefits of the various components of the program. As noted, Staff does not dispute this fact. The issue is whether the Company has provided sufficient information concerning the spending on those programs, and why it was 50% under the U-17735 level. In this regard, the Company has not provided any basis to find Staff's concerns are unfounded. Rather, Mr. Laruwe's testimony that no indication was given of project level spending plans and metrics that would identify the specific system improvements is valid. Along the same lines, the Company did not provide any basis for why it underspent for this program. Absent that information, Staff's $40,000,000 test year budget for Grid Modernization, which will allow for continued investments in the various components of the program, is reasonable.

In response to the request for a Report on the Grid Modernization, the Company indicates it has met with Staff for informal discussions regarding the program, and is willing to continue to do so share information, such as reporting metrics. 6 TR 1164-1165. However, given the wide-range of applications involved in this program, Staff's request for specific information regarding the scope and cost/benefit of each project in the spending plan through 2019, along with pilot results, is reasonable. Accordingly, it is recommended the Commission require the Company prepare and file Report on the Grid Modernization program consistent with Mr. Laruwe's testimony. See 8 TR 2582-2583.

2. <u>Fossil and Hydro Generation Capital Expenditures</u>

These expenditures are intended to ensure plant reliability and compliance with environmental regulations, and "reflects capital spending on projects for its generating plants of $452.4 million for 2014 (Actual), $538.0 million in 2015 (Preliminary), $370.8 million in 2016 (Projected), $258.2 million in 2017 (Projected), $260.1 million in 2018 (Projected), and $246.5 in 2019 (Projected). 7 TR 1601-1602. Mr. Kehoe testified to the expenditures by facility, while Ms. Breining testified to those concerning regulatory compliance. See 7 TR 1604-1618, 8 TR 1720-1734; see also Exhibits A-21-24 and A-45.

a. Contingency Costs

Staff and the Attorney General recommend the exclusion of all, or part, of the contingency costs in the Company's projected capital expenditures for fossil and hydro generation. The Attorney General seeks the exclusion of $35,388,000 in contingency costs included in capital expenditures for the test year. See Exhibit AG-8. Mr. Coppola testified as follows on this point:

> Contingency expenditures are typically amounts above the base forecast of capital expenditures for non-routine projects which are established in the life cycle of the projects in case cost increases are experienced due to unforeseen circumstances. The fact that these added costs are contingent means that they may not be spent in whole or in part. Despite the Company's claim that the amounts may be spent or may be spent on other new work, it does not mean that these costs belong in rate base. It is not fair or reasonable for the Company to recover the depreciation expense and the return on the investment on potential costs that may not be actually incurred but have been added to rate base.
> 8 TR 2319.

In support of this argument, the Attorney General notes that in Case No. U-17735 the Commission held the inclusion of contingency expenditures "is not sound ratemaking practice…." Case No. U-17735, November 19, 2015 Order, pg. 11.

Staff also seeks an adjustment to remove contingency costs of $2,662,000 for the Company's Coal Combustion Residual (CCR) program, and $9,000 for its Waste Water Treatment program. The reason for this adjustment is Staff's contention that what, if any, of these costs will actually be incurred is unknown, and ratepayers should not pay for them given this uncertainty. 8 TR 2560-2561. Staff also cites to the Commission's holding in U-17735, along with its Order in U-17767, which it contends characterizes contingency costs as an acceptable budget factor, but not a cost that should be recovered through rates. Staff contends the costs should be recovered once incurred, assuming the expenditures are reasonable and prudent, in future rate cases.

In regards to its projected contingency expenses, the Company offered Mr. Thomas, a licensed Professional Engineer with over 39 years of experience with the Company in a number of areas, including project management. 4 TR 443. Mr. Thomas testified contingency costs in a project estimate are expected to be expended, and are developed under the following methodology:

> Project contingency estimation, as practiced by the Company, is based on quantitative analysis techniques promoted by the Project Management Institute ("PMI"). We are not using a simple approach such as applying a fixed percentage to each project estimate to establish contingency. To calculate our risk-based contingency, we sum the probability of occurrence multiplied by the potential impact of each potential event on the project's risk register. Mr. Coppola and Mr. Evans incorrectly conclude that it is not fair nor reasonable for the Company to recover the depreciation expense and the return on investment on potential costs (contingency) that may not be actually incurred. The Company's risk-based contingency estimate reflects a probabilistic approach tailored to each individual project. The Company's experience with contingency estimates across a broad range of projects has demonstrated that, on average, the probabilistic approach reasonably forecasts actual consumption of contingency. On a test year basis, a risk-based expected value of contingency expense is a fair and reasonable means of projecting actual capital investments across the Company's broad range of projects.
> 4 TR 445.[8]

As a preface, the Company makes a valid point that MCL 460.6a(1) inveighs against the argument, raised by both Staff and the Attorney General, that because contingency costs are uncertain they cannot, as a matter of law, be included in the rate base. The statute expressly provides for the use of "projected costs…for a future…" test year, meaning none of the costs are certain. Rather, the issue is whether the formulation and amount of the project costs, including contingency costs, are reasonable. This is consistent with the Commission's holding on contingency costs in U-17735: the Company "failed to convincingly explain how the contingency amounts were arrived at, or even specify which projects had contingency amounts that were credited to the blackbox." Case No. U-17735, November 19, 2015 Order, pg. 11. Given

[8] The reference to Mr. Evans pertains to an exclusion Staff seeks for contingency expenditures that is addressed below.

this deficiency, the record in U-17735 did not allow for a determination of whether the "contingency amounts rise to the level of cost items that appropriately belong in rate base earning a return of and on the 'investment'." Id. Accordingly, inclusion of contingency costs in the rate base is not barred as a matter of law.

The Company contends the contingency costs it seeks to have included in capital expenditures are "[a]n amount added to a project estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs." 5 TR 445. The testimony of Mr. Thomas set forth above, along with the testimony of Mr. Fitzgerald he adopted, thoroughly explains the methodology the Company utilizes in projecting contingency costs for capital projects. See 5 TR 432, 437-439, 445-446. The record is devoid of any evidence that this methodology is unsound. Therefore, the Company has established how the contingency amounts in the test year capital expenditures were formulated, and that the methodology used to set those amounts is consistent with accepted project management practices.

In regards to the second issue raised in U-17735, the Company has also provided the projects where contingency costs have been included. For example, the Information Technology program has those amounts broken down by project. See 7 1401-1405; Exhibit A-117. Sufficient information about the contingency costs for projects in other programs, including the historical such costs of program at issue in U-17735, are provided in detail. See 7 TR 1630; 8 TR 1724-1725, 1745; Exhibit A-22.

Based on the foregoing, MCL 460.6a(1) does not bar the inclusion of contingency costs for capital projects in a test year. As for the requirement that such costs must be documented, the Company has provided detailed information on the methodology used to arrive at the projected amounts, and the projects where they are applied. Therefore, the challenge to the inclusion of contingency costs in the rate base should be rejected.

b. SEEG Expenditures

Staff also seeks a $2,455,000 adjustment in $4,909,000 the Company projects in capital expenditures for design and engineering for Waste Water Treatment (WWT), including water segregation costs, as part of its projected Steam Electric Effluent Guidelines (SEEG) capital expenditures. Staff argues this adjustment is warranted for three reasons. First, Mr. Evans testified the Company has not provided any evidence that explains the variations between the projected expenditures and cost estimates for SEEG, making a determination of whether the former are reasonable and prudent. See Exhibits A-24 Exhibit A-121 (confidential). While acknowledging it could have attempted to obtain the information through discovery or cross-examination, Staff contends the Company ultimately has the burden to substantiate its projections. See *In re Detroit Edison*, Case No. U-15768, January 11m 2010 Order, pg. 9. The second basis for the adjustment is the difference between the timeline for the SEEG project in this case and a compliance timeline submitted to the Michigan Department of Environmental Quality (DEQ) that indicates the design and construction of the project will occur in 2020-2024. 8 TR 2565-2566; Exhibit MEC-52. Given this, the expenditures during the test year are necessarily over-projected. Finally, Mr. Evans notes that in its last two rate cases, the Company over-projected its SEEG expenditures. Specifically, in 2014 it projected $17.48 million but only spent 1.379 million, and in 2015 it projected 7.062 million but only spent $1.053 million. 8 TR 2566-2567. Given this history, Staff contends a 50% reduction in the projected expenditure is warranted.

The Company contends none of the reasons cited by Staff for the adjustment are valid and the projected expenditures for SEEG design and engineering should remain at $4,909,000. In support, it cites to the rebuttal testimony of Ms. Breining that indicates the Company was unable to provide the information sought by Staff because "the costs for the SEEG project cannot be carved out in the specific subcategories as requested." 8 TR 1741. Ms. Breining then supports this contention with a detailed explanation of the WWT project. Id., 1741-1742; Exhibit S-8.4; Confidential Exhibit A-86. Staff seemingly acknowledges the Company has provided all the information the cost components of the WWT project. See Initial Brief, pg. 14, footnote 14, Dkt. #363. Irrespective of whether Staff has withdrawn this basis for the proposed adjustment, the record indicates the Company has substantiated its projected expenditures for WWT design and engineering.

As for the conflicting timeline, the Company contends it intends to fully comply with SEEG by year-end 2021. Id., 1731, 1742. The communication with the DEQ represents an alternative compliance schedule, relative to the Company's pending application to renew its NPDES permits for the subject facilities that the agency has not approved. Id., 1742. Further, whatever the DEQ ultimately decides, Ms. Breining testified it would be imprudent to not proceed with the design and engineering work during the test year. This is a valid point in that even if compliance was pushed out, which is by no means certain, it is necessary to commence the design and engineering work on WWT. Finally, Ms. Breining attributed the 2014 and 2015 over-projections to delays in the promulgation of the SEEG rule, and the Company's efforts to be in a position to comply with that rule when it ultimately went into effect. Id., 1743-1744. This too is a valid point, given the SEEG rule was expected to be proposed in 2013 and finalized in 2014, but was not finalized until November 2015. Id.

Based on the foregoing, the Company's approach to complying with the SEEG rule, including the test year expenditure of $4,909,000 for WWT design and engineering services, is reasonable and prudent. Therefore, Staff's proposed 50% downward adjustment of those costs should be rejected. However, the Company has agreed with Mr. Evans' request that subsequent to the issuance of the Order in this case, biannual meetings be held so that Staff receive updates on all environmental projects and the status of pending and/or proposed environmental regulations as it relates to those projects. See 8 TR 2569-2570.

The Attorney General seeks an $8,200,000 reduction in the projected hydro generation expenditures, which is 50% of the Company's proposal. The reduction is based on Mr. Coppola's determination that the "forecasted expenditures are very preliminary and FERC approval…" still must be obtained, leading him to conclude "that at least half of the expenditures forecasted…" will not be incurred during the test year. 8 TR 2325. In response, the Company contends it has provided a detailed listing of the projects and their purpose and cost estimates based engineering studies and vendor quotes. See 7 TR 1612-1613, 1627-1629; Exhibit A-45. Mr. Coppola does not take issue with any of this evidence, but rather opines that not all of the projects can be completed by August 31, 2017, so a 50% reduction in the expenditures is warranted. Because there is no evidentiary support underlying Mr. Coppola's opinion, such as what projects he contends can't be completed and why, the proposed reduction cannot be sustained.

The MEC/NRDC/SC also takes issue, through the testimony of Mr. Koehler, with expenditures for generation and environmental compliance at the D.E. Karn Units 1 & 2, and J.H. Campbell Units 1 & 2 (Medium 4). 8 TR 2148. For the most part, the testimony concerns expenditures for the period covered under the proposed Investment Recovery Mechanism (IRM), which would be in effect through September 1, 2017 through December 31, 2019. The viability of that proposed mechanism is discussed below. For the purposes of capital expenditures during the test year, the Company's contention that the testimony is, for the most part, irrelevant is well taken given it has agreed to the removal of the Generation and Environmental Compliance programs from the IRM under consideration in this case. See 5 TR 690. Mr. Koehler's testimony regarding test year expenditures is essentially that some may be avoided if the facilities were retired in 2021. 8 TR 2165-2167. Mr. Koehler did not identify which specific expenditures he would term avoidable or indicate how foregoing the expenditures would not affect the operation of the facilities if the decision is to ultimately retire them in 2021. Conversely, the Company has set forth the projected capital expenditures at these facilities for the test year, and established that those expenditures are, standing alone, necessary to ensure the continued reliability and efficiency of those facilities. 7 TR 1604-1609, 1635. Accordingly, the MEC/NRDC/SC contention regarding projected capital expenditures during the test year at the Medium 4 cannot be accepted.

Based on the foregoing, the Company has established its projected capital expenditures for fossil and hydro generation are reasonable and prudent, and thus should be approved. In conjunction with that approval, it is recommend the Commission approve Staff's request to require biannual meetings for the purpose of receiving updates on all environmental projects and the status of pending and/or proposed environmental regulations as it relates to those projects. See 8 TR 2569-2570.

3. Information Technology (IT) Capital Expenditures

The Company's IT Department's capital expenditures are set forth in Exhibit A-60, and entail:

> Summary of Projected Electric & Common O&M Expenses for the years 2014, 2015, 2016, and 12 Months Ended August 31, 2017 summarizes the Electric allocation of actual and projected IT Department O&M expenditures.
> Specifically:
>
> - Column (a) provides the O&M expense category.
> - Column (b) identifies the 2014 actual O&M expense as $49,926,000.
> - Column (c) identifies the 2015 preliminary O&M expense as $47,722,000.
> - Column (d) identifies the 2016 projected O&M expense as $43,278,000.
> - Column (e) identifies the 12 months ended August 31, 2017 projected O&M expense as $43,326,000.
> - Column (f) identifies the source reference.
>
> 7 TR 1376.

The programs for which the expenditures are set forth in Exhibit A-61, and include:

> Summary of Projected Electric & Common Capital Expenditures for the years 2014 through 2019 identifies the electric allocation of projected capital expenditures to procure, install, and implement the software and infrastructure identified earlier in this testimony to meet business requirements. Specifically:

- Column (a) provides the description of the capital expenditures;
- Column (b) identifies the 2014 actual capital expenditures as $74,172,000;
- Column (c) identifies the 2015 preliminary capital expenditures as $91,702,000;
- Column (d) identifies the 2016 projected capital expenditures as $62,974,000;
- Column (e) identifies the eight months ended August 31, 2017 projected capital expenditures as $32,012,000;
- Column (f) identifies the four months ended December 31, 2017 projected capital
- expenditures of $24,150,000;
- Column (g) identifies the 2018 projected capital expenditures of $54,294,000;

- Column (h) identifies the 2019 projected capital expenditures of $59,212,000; and
- Column (i) identifies the source reference for each category listed.

7 TR 1381

The Company contends the projected test year capital expenditures for IT are reasonable and prudent and requests they be approved.

Both Staff and the Attorney General seek to remove the contingency costs from the IT capital expenditures although they arrive at different amounts for those costs. Ms. Fromm, who reviewed the programs and expenditures and found them reasonable, testified the contingency costs were $4,061,000 for 2016. 8 TR 2612; Exhibit S-10.4. Mr. Coppola set the amount at $5,605,000 for 2016, and $2,707,000 for 2017. 7 TR 1404; Exhibit AG-8. According to Exhibit A-117, which is a Staff audit response, the Company is projecting IT contingency costs only in 2016, and the amount is $4,061,000.

As discussed under the Fossil and Hydro Generation capital expenditures analysis, *infra*, contingency costs are not barred as a matter of law. Rather, the issue is whether the Company has explained "how the contingency amounts were arrived at…" and specified "which projects had contingency amounts that were credited to the blackbox." Case No. U-17735, November 19, 2015 Order, pg. 11. The Company has satisfied both prongs of this test. 7 TR 1403-1404; Exhibit A-117. Therefore, the projected capital expenditures for IT projects, including $4,061,000 for contingency costs, are reasonable and prudent, and should be approved.

4. Smart Grid/Advanced Metering Infrastructure Capital Expenditures

Mr. Warriner testified to general parameters of this program:

> The Consumers Energy SG/AMI Program was established in 2007 with the objective of investing in advanced metering technology upgrades that will provide multiple benefits to customers. The AMI system includes the following: 1.8 million electric meters and 0.6 million gas meter modules capable of transmitting accurate daily meter reads and power outage notifications and receiving remote operational signals ("smart meter"); a two-way cellular based point-to-point communications network; development and integration of new systems to support the use of the data for billing and operational uses; and a flexible customer web portal that is updated daily to provide for customer awareness of energy usage and support energy efficiency and demand response programs. This technology upgrade provides the platform for ongoing implementation of various customer and operational benefits detailed in my testimony. These smart meter benefits for customers include new customer programs and billing options for electric and electric/gas combination residential, commercial, and industrial customers. Operational data provided by smart meters will enable future advanced grid applications to build upon the benefits of the Company's investment in SG/AMI technology.
> 7 TR 1417-1418

The Company has installed 836,667 smart meters as of January 2016, which approximately half of the total projected installs, and was on course to complete a number of programs associated with those meters in 2016. 7 TR 1420-1423. All told, the smart meters and gas modules constitute a $750 million capital expenditure between 2007-2017, with 88% of those costs allocated to Electric Operations. Id., 1424.

For the Smart Energy Program, projected electric and common capital expenditures in 2014-2017, which includes field equipment/facilities, meters, software/systems development, SG infrastructure, and program engineering/design and management, are projected at $428,856,000. 7 TR 1424-1426; Exhibit A-62. Projected Electric & Common O&M AMI expenses for the test year are projected at $9,423,000 for

Program Management, and $4,340,000 for O&M costs arising from the purchase and installation of AMI meters. 7 TR 1427-1428; Exhibit A-63.

Mr. Warriner testified to the cost/benefit analysis 2007-2032:

> The Company's business case for SG/AMI includes both costs and benefits for both electric only and electric/gas combination customers. The Net Present Value ("NPV") [footnote omitted] calculation in the business case is based on numerous tested assumptions for both costs and benefits that are updated as the program progresses. The key areas of variability in annual costs are the meter/module installation schedules and the systems modifications and new systems development requirements. The areas of variability on the benefits side (primarily electric) include the addition of new customer programs, the response of customers to demand response programs, and the value of avoided capacity requirements due to peak load reductions which result from AMI-enabled programs and capabilities. The current program net Present Value of Revenue Requirements ("PVRR") calculation shows savings to customers of $29.3 million (a reduction of $29.3 million in NPV revenue requirements) assuming long-term generation capacity prices are 75% of the projected Cost of New Entry ("CONE"). [footnote omitted]
> 7 TR 1428; See also Exhibit A-64.

In addition to the foregoing, Mr. Warriner attributed a number of benefits accruing to the Company and its customers from this Program. 7 TR 1431-1435.

Based on this evidence, and consistent with the numerous of prior cases addressing AMI costs recovery, the Company requests a determination its AMI investments satisfies the NPV cost/benefit analysis, are reasonable and prudent, and should be approved.

Staff raises three issues with the Smart Grid/AMI Capital Expenditures proposed by the Company. The first issue concerns the installation of 46,749 meters in September 2017. Ms. Fromm testified that since the meters were purchased and installed outside the test year, "the cost associated with these meters are not used and useful…." 8 TR 2610. To ascertain those costs, Ms. Fromm determined of the meters projected for purchase during the test tear, 11% would be purchased in September 2017, which constitutes a downward adjustment of $7,219,000 in the program's capital expenditures. Id., Exhibit S-10, pg. 1.

In response to Staff's proposal, the Company contends no basis was provided for Ms. Fromm's conclusion that the meters installed outside the test year are not "useful". Further, Mr. Warriner testified that conclusion:

> [C]ontradicts the Federal Energy Regulatory Commission ("FERC") Code of Regulations Uniform System of Accounts [footnote omitted], which prescribes how the cost of meters are to be reflected in plant-in-service accounts. The Electric Plant Chart of Accounts definition for Account 370 (Meters) states: "This account shall include the cost installed of meters or devices and appurtenances thereto, for use in measuring the electricity delivered to its users, whether actually in service or held in reserve."
> 7 TR 1452-1453.

Under these FERC accounting regulations, the Company treated meters purchased in August 2017, but planned to be installed in September 2017, as part of its plant-in-service account. 7 TR 1453. Based on this testimony, Staff's recommendation of a downward adjustment that reflects the costs associated with meters that are projected to be installed in September 2017 cannot be sustained.

Staff also seeks a downward adjustment to the $4,892,000 for load control switches associated with the Company's Direct Load Administration (DLA) Program. Underlying this request is Mr. Laruwe's determination that despite an installation projection of 8,300 switches in U-17735, none were installed in 2015. 8 TR 2596. In that case, Staff recommended the DLA program not be approved because the functionality of the technology had not been verified. Mr. Laruwe testified that concern remains given the delay in deployment, which the Company attributed to the need for extended testing. In addition to the concern about the viability of the technology, Staff contends the projection that the Company will install 45,000 switches during the test year, but only has 1,522 customers in the program. See Exhibit A-10. Staff recommends cost recovery be limited to the amount necessary to serve those customers, which is estimated at $403,000[9], and would constitute a $4,489,000 reduction from the projected Smart Grid/AMI capital expenditures. 8 TR 2596.

The Company contends the customer participation level underlying its projected expenditure is based on a methodology that is intended to reflect the growth in DLA Program participation. 7 TR 1455; Exhibits A-10 and 11. The Company expects to reach that level during the test year given that the DLA systems are operating and functional and customer outreach has begun. 7 TR 1455. Therefore, the projected capital expenditure of $4,892,000 for 18,476 direct load control switches under the DLA Program is reasonable. Id.

Mr. Laruwe makes a compelling argument that based on past performance, specifically the fact that none of the 8,300 switches projected in U-17335 were installed in 2015, a point the Company does not challenge, diminishes the installation projection in this case. Further, the Company has not refuted Mr. Lawure's contention that the functionality of the switch the Company elected to utilize remains in doubt, and ratepayers should not be responsible for its costs until it is established the Company can successfully install and operate them. Rather, the only evidence the Company offered is Mr. Warriner's general statement that DLA systems are operating and functional. The Company also failed to indicate how a mailing to 40,000 "potential

[9] In its initial filing, the Company projected the capital expenditure for the switches at $10.449 million. Exhibit A-62, Line 1. Given the cost of the switch is generally agreed to be $264.78, the projection represents the installation of 39,500 switches during the test year. In his rebuttal testimony, Mr. Warriner indicted the projection is now for the installation of 18,476 switches, which would reduce the capital expenditure to $4.5 million. 7 TR 1455.

customers" will translate to the significantly increased participation level projected during the test year, especially given that the level has remained essentially stagnant since the Direct Load Control Pilot in 2010.

Therefore, the Company's initial projected capital expenditure for direct load control switches, $10.449 million, and revised expenditure, $4.5 million, cannot be accepted. Rather, Staff's projected test year capital expenditure of $403,000 for the load control switches associated with the Company's Direct Load Administration Program should be adopted.

The final issue Staff raises is the future reporting requirements concerning the AMI program, particularly the results of the programs the Company has identified in its benefits business model, subsequent to the completion of meter installation in 2017. To that end, Ms. Fromm testified:

> Staff proposes that the Company submit annual smart grid reporting metrics that show the Commission how the proposed benefits are coming to fruition with the implementation of the AMI meters. The proposed annual reporting metrics are identified in Staff Exhibit S-10.3 and were created with the intention of using previous reports' data as a baseline in order to tie the approved expenditures to the benefits delivered to the customers. It is also Staff's intention to have a single annual report for both the electric and gas related metrics based on a full calendar year. Upon review of the report, Staff believes it is necessary to be able to remove existing and/or add new metrics as appropriate.
> 8 TR 2611-2612.

The Company expressed concern with certain of the metrics set forth in Exhibit S-10.3, but generally agreed to the advisability of meeting with Staff after this case concludes to develop appropriate reporting metrics and reduce reporting requirements duplication. 7 TR 1455. [10]

5. Plug-In Electric Vehicle (PEV) Charging Infrastructure Capital Investments

The electric vehicle (EV) market is undergoing rapids expansion, with 300,000 vehicles currently in service nation-wide, with 1,000,000 expected in service by 2017. Michigan has been important player in the market, through both the automotive industry and being in the top ten states in sales. However, Michigan has less than 2% of the nation's charging stations, which will inevitably lead to a slowing of the market. The Company is proposing what it terms is an innovative program to facilitate the viability of EV vehicle usage in Michigan through this Program, which Mr. Morales outlined:

> The PEV program aims to install PEV infrastructure in major cities throughout the Lower Peninsula over a period of two to three years. The PEV infrastructure will consist of DC fast chargers at 30 locations and 750 240V AC charging stations (see Exhibit A 51 (JHM-3)). These charging stations will enable a PEV to recharge up to 80 percent of its battery in approximately 20 minutes. Installation of the 240V AC chargers will begin in higher-populated metropolitan areas and expand to smaller cities. These stations will be strategically placed in public and private areas to increase visibility of the stations. By identifying locations in Michigan with limited or no charging access, we can help Michigan residents be more comfortable with their decision to purchase a PEV when they see widespread availability of charging stations. We would partner with businesses in high-traffic areas to install one to two charging stations per site, with no installation costs incurred by the host. These locations would include places where people stay for a considerable amount of time, such as restaurants, malls, movie theaters, hospitals, hotels, airports, and large workplaces. These stations will be placed in all areas of the community to service customers of all income and socioeconomic levels. In addition to public charging stations, we will provide Consumers Energy electric customers who purchase a PEV a reimbursement incentive toward the installation of a 240V home charging station. The home charging incentive

[10] The Company requests that the information contained in Exhibit AG-7 concerning the Smart Grid/AMI Program be disregarded because Mr. Coppola has confirmed it is inaccurate. See 7 TR 1451-1452; see also Exhibit A-123 (discovery response 17990-CE-AG-8). While the Attorney General is not proposing any reduction in the program's projected capital expenditures, the Company's assertion that AG-7 is unreliable, and thus should not be afforded any weight, is valid.

> helps reduce the additional expense a customer would encounter when switching to a PEV.
> 6 TR 866-867

The program's general parameters, i.e. public charging stations underwritten by ratepayers and installed on private property (site hosts) such as shopping malls, hospitals, large office buildings, is similar to undertakings by California's three major utilities that will result in the installation of public PEV infrastructure to support 1.5 million EVs by 2025. The public charging stations would be installed and maintained by the Company while the site host would be responsible for the cost of electricity used, which it could pass on to the consumer or pay itself if it wanted to offer free charging as an amenity to its patrons. The home charging station would be a rebate to the homeowner who installs a station of their choosing.

For the purposes of this case, the capital expenditures proposed by the Company for both components of the PEV program are:

> The DC fast charge stations are estimated to cost $100,000 per station for installation, with a total cost of $6 million for 60 stations. The 240V AC charging stations are estimated to cost $12,000 per station for installation, with a cost of $9 million for 750 stations. Capital costs for both the AC and DC charging station installations total $15 million for the period 2016 through 2019, and total $10.625 million for the period 2016 through the end of the test year (see Exhibit A-49 (JHM-1)). There is no charge to the host site for installations, and usage charges to the businesses supporting the stations will be minimal. The station costs will be recovered through base rates as part of the Company's revenue requirement calculation. The Company's electric customers who purchase PEVs and choose to install at-home charging station equipment will receive $1,000 incentive toward the installation of a home charging station. An estimated 2,500 incentive payments will be given out to customers within three years, totaling $2.5 million in O&M costs. The O&M costs of $150,000 (see Exhibit A-50 (JHM-

2)) for the test year period should also be included in the Company's revenue requirement. 6 TR 873-874. [11]

The Company seeks approval of $10,625,000 for the PEV Infrastructure Program in the test year, and projects total costs of $15,000,000 through 2019.

a. Staff

Staff acknowledges "that a robust publicly-available charging network will be key to widespread acceptance, and adoption, of electric vehicles…." 8 TR 2624. This essentially tracks the Company's stated purpose of the PEV Program: "Michigan should stand behind the growth of [the EV] market, and the Company can help support this new strategic direction by incentivizing PEV adoption by providing charging stations throughout the state for public use." T TR 867-868. However, Staff does not support the Company's proposal as it pertains to public charging stations and suggests an alternative cost recovery for home charging. Staff also requests the Commission institute a Michigan Electric Vehicle Collaborative (MEV Collaborative) to develop a statewide plan to govern utility involvement in PEV Charging Infrastructure.

Staff's position is based on the testimony of Mr. Ozar who noted the benefits that will result from increased EV use, and the challenges from that increase to utilities:

> According to the US Energy Information Administration (EIA), 2015 retail sales of gasoline in the United States averaged 384.74 million gallons per day. At a retail price of $2.64 per gallon, this would translate into a national expenditure of $1.02 billion per day. In contrast, retail sales of electricity in the US during 2014 were approximately 10.3 billion kWh per day, and at an average retail price of 10.27 cents per kWh translates to a national electric expenditure of $1.05 billion per day. This means that expenditures on gasoline for transportation are of the same order of magnitude as the current total retail-sales of electricity. Clearly the

[11] On re-direct, Mr. Morales clarified the home charging rebate is capped at 2,500 customers, and the $1,000 incentive payments were not included in forecasted O&M expense exhibits, but going forward will be classified in that manner. 6 TR 954-955.

> conversion of even a portion of the gasoline segment of the motor-fuels market, into plug-in electric vehicles (PEV), has the sheer scope and magnitude to radically transform the electric industry. A theoretical complete conversion could nearly double utility sales and revenues, and in the process permanently reshape the traditional utility load-curve. There is a strategic opportunity here for utilities such as Consumers Energy to offset declining load-growth due to persistent implementation of end-use efficiency and distributed generation resources by customers – if charging times are properly managed. [Distributed energy is power produced at the point of consumption, by a grid connected device i.e. a distributed generation resource, and giving customers control of their energy.]
> 8 TR 2620-2621

In regards to management of charging time, Mr. Ozar relies on a 2011 Study funded by the Commission to examine the effect of EVs. Exhibit S-12. The Report quantified the impact of charging on the system and concluded the negative effects, including impacts to infrastructure, system reliability, and costs, will be much greater from peak-period charging. 8 TR 2621-2622; Exhibit S-12. While it is necessary to have a comprehensive program for EV charging, i.e. both public and home, the latter "must be the predominant form…." Id., 2622. Mr. Ozar explained the basis for that opinion is home charging will typically occur at night, which will not only minimize impacts to the grid, but increase operational efficiency by spreading costs over a larger sales-base and enhance renewable energy sources. Mr. Ozar acknowledges the necessity of public charging infrastructure, but recommends an approach that results in them being widely available, but rarely used. Id., 2624.

Mr. Ozar views the Company's public EV charging proposal as raising significant policy questions. The first is whether a regulated utility own and operate public charging stations will serve to diminish private investment in the market. This is likely given the Company's ability to recover construction and operating costs for the stations through rates, as opposed to a private party having to recover them from revenue generated from the stations. The second is whether the nature of the program is "consistent with the essential basis for public utility regulation of a natural monopoly?" Id., 2627. Mr. Ozar concludes it is not, noting an EV charging station is a component of a broader, and highly competitive, motor fuels market, while the Company operates in a natural monopoly environment. The disruption to a competitive market that would result from the Company's direct investment into it may be avoided through rebate/reimbursement program funded through rates, similar to energy efficiency programs that could actually stimulate private investment. Id., 2627-2628. The third issue is whether ratepayers should pay for a service that they do not use, which Mr. Ozar determined is appropriate provided the Company's participation is not open-ended, based on the benefits that would flow from a significant off-peak demand increase. Mr. Ozar also indicated it is necessary to determine whether private investment, standing alone, is sufficient to build out a robust charging network in Michigan. If not, Mr. Ozar indicated regulated utilities may have to enter the market.

Finally, Mr. Ozar testified to numerous other attendant issues arising from the Company's public charging proposal, such as the optimal location and type of stations, the future of EV technology and its impact on charging, current regulatory impediments to market expansion, and the role of renewable energy generated infrastructure. Id., 2629-2637. All of these issues would be appropriate for consideration by the MEV Collaborative Staff is requesting.

In general, Mr. Ozar views the Company's home charging incentive/reimbursement as in the public interest, and seeks its approval with the following modifications:

Staff is recommending that customers who accept a Consumers Energy reimbursement toward the installation of a Level 2 home charging station, be required to enroll in a dynamic peak-pricing tariff as a condition of acceptance. At this point in time, the tariff could either be a whole-house dynamic-pricing tariff, or a specific EV time-based tariff. Such a condition, is fully consistent with a voluntary opt-in policy for dynamic pricing, since acceptance of a cash incentive is at the customer's discretion. Second, Staff recommends that within 6 months of the date of the Commission's order in this proceeding, that Consumers Energy provide the Commission with a report on how it intends to use its smart grid infrastructure, along with other technology aids, to help customers manage charging, and charge times, of their electric vehicles. Third, the $1,000 reimbursement structure proposed by Consumers Energy should be modified to take advantage of learnings from the utility's Energy Optimization program. For the EO program, rebate levels are set in a manner that maximize participation, at a minimum cost. This might involve working with a third-party program evaluator who has expertise in this area. In contrast, what the utility appears to be proposing is a simple $1,000 cap on reimbursement for equipment and installation. Staff does not believe that this approach provides maximum value to the ratepayers who are subsidizing the home-charging program. Fourth, the program should be expanded to cover EV charging station reimbursements for tenants of multi-family housing units. Multi-family housing presents unique challenges for charging electric vehicles, and the build-out of such infrastructure. Charging stations for multi-family housing are technically publicly-available charging, most likely served on a commercial electric rate, but the essential character of the usage is closely aligned with home charging. In fact, I would not be off-base to say that multifamily EV charging constitutes home charging, since usage profiles should be identical to traditional home-charging. Consumers Energy will need to develop an EV charging station reimbursement structure similar to that recommended for owner-occupied homes, the essential difference being that the utility will be working with building owners, (and possibly local governments - for curbside parking). It is recommended that as a condition for acceptance of a reimbursement by a multi-family housing customer, that the resale option [C4.4 (C)] should apply to the ultimate end-user, as a per kWh cap. This provision designates an all-inclusive, fixed-rate, resale charge, thus, protecting ultimate resale customers. If in the alternate, the multi-family building operator, or local government desired to charge a flat fee for electricity, it would be capped at $45 per month, or $1.50 per day. This coincides approximately with the flat-fee option [Option 2] in DTE's Experimental Electric Vehicle tariff, Rate Schedule D1.9. In making these recommendation, it is recognized that this is a stop-gap measure and that a long-term strategy for protecting the interests of tenants at multi-family co-located "public" charging stations, should be taken-up by the Michigan Electric Vehicle Collaborative. 8 TR 2638-2639

Mr. Ozar also notes that since home charging is in its early-stages it is difficult to project participation levels with any degree of reasonable certainty for a test year. Therefore, he recommends authorization for the creation of a regulatory-asset account that would allow for future recovery of actual costs that were reasonably and prudently incurred. Staff provides more detail to its proposal, under both a short-term and long-term perspective, along with proposed amended language for the C4.4 Resale tariff that serves to remove EV charging service from the resale prohibition, and issues for the proposed MEV Collaborative to address. Initial Brief, pgs. 157-161. Dkt. #363.

b. ChargePoint

ChargePoint is a manufacturer of both public and home EV charging stations, and offers support on many level to site hosts of the stations. ChargePoint does not set pricing at the stations, or collect revenues from the consumers of the charging service, and has a presence in Michigan. 8 TR 2752-2753. ChargePoint agrees with the home charging component of the proposal, but notes the station should have communication capability with the Company for current benefits, such as providing data and load management ability. To that end, it recommends the Commission maintain oversight of the program and set a base qualifications for eligible stations.

Through the testimony of Mr. Ellis, ChargePoint took issue with the Company's proposed public EV charging stations:

> Charging Infrastructure proposal through the testimony of Mr. Ellis. Utility programs should not pick and choose beyond-the-meter end-use technologies like the commodities they procure at the lowest cost because it prohibits competition in the market and increases investment risk. Alternatively, utility programs should qualify and incentivize capabilities and characteristics of end-use technologies to accelerate access to tools that create grid benefits. Rather than accelerate the EV charging market, procuring and deploying 750 L2 stations and 60 DC Fast Chargers that

> are owned and operated by Consumers could lead to market stagnation in Michigan. A program of this magnitude will drive EVSE vendors out of Consumers' service territory, as competing with free is very difficult. Rate-payers benefit from a robust and competitive market as they have access to the latest advancements in charging technologies and services in the quickly evolving EV market. Technology is advancing too quickly for utilities to keep up with, and, a utility procurement would "lock down" a technology available today for a decade or more – with a product feature set that was selected for the EV driver by the utility (who has very little experience in the EV industry) - increasing rate-payer risk of the investment and limiting potential grid benefits. Specifically, the PEV Program as proposed would have a negative impact on competition, innovation, and customer choice and will not enable scale and build a sustainable EV market.
> 8 TR 2767-2768.

Mr. Ellis opined the Company's subsidization of the program, which removes the site host from active role in the charging station, is a "fundamentally flawed idea" because having a financial stake makes that entity "far more likely to actively support the successful installation and ongoing preventive maintenance…" of the stations. 8 TR 2779.

Mr. Ellis also testified that rather than stimulate EV viability in Michigan, which is the stated purpose of the project, the Company's proposal:

> [L]imits any benefits of the investment, locks in technology capabilities in a quickly evolving market, and would be an inefficient use of ratepayer funding as the same grid benefits can be created with reduced investment and risk. Historic and projected growth in the EV charging market show that private dollars are increasingly flowing into the market. And, cutting out private funds entirely will force Michigan to lose out on an opportunity to leverage capital investment, reduce its risk of engagement and extend the value of every ratepayer dollar invested in an EV charging program. Reducing the risk of investment by limiting the scope of the utility engagement to either incentivizing the installation costs of a make ready through a programmatic rebate mechanism or subsidize make-ready work in exchange for private investment in smart EV charging equipment is a better EV program design. The value of the program would increase, be more sustainable and create a bigger positive impact on deployment of EV charging infrastructure by spreading incentives to a greater number of customers. This approach is also scalable to future market needs

> including electric buses and other transportation technologies – increasing the value to the grid by creating more beneficial use of electricity as a transportation fuel to put more kilowatt hours through the system and reducing fixed grid costs. This puts downward pressure on rates over the long-term and creates benefits for all ratepayers.
> 8 TR 2779-2780

In effect, Mr. Ellis' concern is that as a regulated monopoly, the Company's entry into the EV charging market will have a "chilling effect on innovation" and force competitors who can't provide free equipment and services to a site host out of the state. Id., 2781.

Based on ChargePoint's experience in the market, and to foster its growth in Michigan, Mr. Ellis recommends the following modifications to the program:

- Near-Term: Reasonable Investments
  - Provide exemption for owners and operators of EV charging stations from being considered public utilities to permit pricing by kWh;
  - Expand residential rebate requirements to include smart and connected charging station capabilities;
  - Expand rebates to commercial charging station applications including the L2 and DC fast charging use cases;
  - Limit the utility role to make-ready investments;
  - Treat all appropriate utility investments as regulated assets providing a rate of return for the utility to incentivize engagement to help drive electrification;
  - Create new line extension rules to provide low cost access to charging in MUDs and underserved communities; and
  - Engage education and outreach on electricity as a transportation fuel to help drive awareness of EV technologies and market acceptance

- Longer-Term: Coordinated Action
  - The Commission should open a separate docket to determine the most scalable and sustainable approach to growing the EV and EV charging markets in Michigan. Stakeholders for this process should include, at a minimum, a range of policymakers and industry representatives from across the EV and EV charging ecosystem;
  - Engage rate reform to lessen the barriers created by high operating costs of higher powered charging equipment from demand charges through innovative cost recovery mechanisms such as volumetric rates;
  - Expand development of equitable access to clean/electrified transportation; and

- o Prepare for higher rates of charging for the next generation vehicles by implementing new internal processes for longer-term planning to incorporate EVs in utility strategic roadmaps.

8 TR 2790-2791.

c. Attorney General

The Attorney General objects to the program in its entirety through Mr. Coppola's testimony that it is "ill-conceived and a financial burden…." on ratepayers. 8 TR 2326. In support of his characterization of the financial burden contention, Mr. Coppola testified that given the 2,600 EVs in the Company's service area, the $10,600,000 investment equates to $4,000 per vehicle.[12] Further, the Company did not prepare a financial cost/benefit analysis that would justify the expenditure.

d. MEC/NRDC/SC

Mr. Jester characterized the program as "incomplete and not well-focused" for a myriad of reasons and offered suggestions concerning issues surrounding EV charging such as how to integrate it with the system promote the growth of the market. See 8 TR 2216-2227. Mr. Jester recommended immediate action on EV charging and recommended program components such as imposing some levels of charges on EV drivers for delivered power and recovery of the infrastructure costs through a utility sponsored payment network. Id., 2227-2230. However, he did not expressly opine on the viability of what the Company has proposed in this case: approval of $10,625,000 test year capital expenditure for the PEV Infrastructure Program in order to install 60 DC fast chargers at 30 locations and 750 240V AC charging stations in major cities in its

[12] Mr. Coppola also testified the Commission should not endorse the Company's proposal to provide free electricity at the charging stations, places a further burden on ratepayers. However, the PEV Charging Infrastructure Program involves the site host paying for the electricity.

service area. Mr. Jester also supports the formation of a MEV Collaborative to address the issues implicated by the Company's proposal.

Undoubtedly, the Company's PEV Infrastructure program is a well-intentioned effort to foster the growth of EVs in Michigan through installing public charging stations in its service area, and encouraging home charging stations. However, as clearly set forth in Mr. Ozar's testimony along with the testimony of Mr. Ellis and Mr. Jester, the program raises significant policy questions that must be addressed. For example, the program could actually inhibit the growth of a charging station network by discouraging other private actors, such as ChargePoint, from also entering the market because their costs will necessarily be higher. It is axiomatic that a site host would elect to participate in Company's program, which only requires payment for electricity used, as opposed to incurring the costs for the infrastructure on its own through a private entity. Mr. Ozar's testimony regarding the impact on the system due to an increase in peak demand from EV charging is also well-taken. While that concern would seemingly not be directly implicated by the program at issue in this case, it will be as the EV market expands and should be addressed before the Company enters the public charging market. The home charging rebate program does not raise the same issues that inveigh against the public charging station proposal.   However, the testimony of Mr. Ozar, Mr. Ellis and Mr. Jester all raise concerns that need to be addressed particularly the extent of the program, the requirement for "networked" charger that can communicate, how to address multi-unit dwellings, and pricing.

Based on the foregoing, the $10,600,000 sought for PEV Infrastructure should be disallowed. To properly address the Company's role in the development in this area, and address the multitude of issues raised by Mr. Ozar, Mr. Mr. Ellis, and Mr. Jester, concerning that role, the Commission should establish the MEV Collaborative that includes all stakeholders in the EV market for the purpose of assisting in the development of a master plan for Michigan's EV's charging network. While the concerns raised regarding the home charging aspect of the PEV Infrastructure Program do not reach the level of those implicated by the public charging station proposal, they are significant enough to warrant further study. Therefore, the expenditures for that aspect of the program should also be denied until those details are resolved. If the Commission concludes those issues do not rise to the level to reject the expenditures for a home charging rebate program, the modifications Mr. Ozar proposed should be required. See 8 TR 2637-2640; see also Staff Initial Brief, pgs. 157-158.

6. <u>Demand Response Capital Expenditures</u>

The general parameters of the Demand Response (DR) Program were testified to by Mr. Morales:

> Each business customer that signs up for the program is contracted for a specified load (kW) reduction. We work with individual customers to set up a demand reduction plan at their facility that will be implemented when a demand response event is called, i.e., a time when electricity demand and cost are highest. A number of customers of different sizes will be put together through this process to create a demand response portfolio. The demand response portfolio is a capacity resource that can be called upon during peak times of system usage to reduce overall electricity demand. When the Midcontinent Independent System Operator ("MISO") expects the grid to be strained because of high electric demand or during high market costs, a notification will be sent out to all of the customers within the portfolio ahead of the event, informing them of when they need to shed load. When the event occurs, they will follow their established energy reduction plan, thus decreasing their electric demand. When each customer in the portfolio does this, it will reduce the stress on the grid, producing a Michigan-first, flexible commercial and industrial energy resource that can help meet capacity needs.
> 8 TR 860-861

Participation in the program is voluntary, and the terms of the relationship between the commercial or industrial customer, which must have a peak energy demand of 250 kW outside the interpretable or retail open access rate, and the Company, e.g. the amount of incentive payments and frequency of events, is established through a contract. 2 TR 864-865; Exhibit A-52. The payments are characterized as either capacity, per kW of reduction delivered, or energy, a kWh reduction during a called event. Id., 865.

The Company initiated the DR Program as a pilot in 2015 in order to manage its peak capacity needs and reduce the added expense of increased generation/capacity contracts necessary during those periods.[13] During the pilot, 28 customers ranging in size of 250 kW to 14 MW entered into contracts for 7.7 MW of capacity, and the Company expects that ultimately it can reach 150 MW of capacity in 5 years, with another 20 MW of capacity added by opening the program to smaller customers. Id., 864. Mr. Morales provided the following regarding the costs for the DR Program:

> O&M costs to conduct the pilot totaled $990,000 in 2015, which consisted of customer acquisition, technology platform, solution software, and data collection meters to enable the program and validate participation (see Exhibit A-50 (JHM-2)). The O&M costs in the test year for this proceeding total $2.8 million (see Exhibit A-50 (JHM-2)), which should be included in the revenue requirement for this case. Additionally, the capitalized costs for the period 2015 through the end of the test year [$996,000], as shown in Exhibit A-49 (JHM-1), should be included in the Company's rate base for the test year.
> 8 TR 864.

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[13] In an Order entered while this case was pending, the Commission indicated its commitment "to appropriate consideration of DR programs as an alternative to new generation and to help lower costs." Case No. U-18013, March 29, 2016 Order, pg. 3. Subsequently, the Commission held the Company should, in its next rate case, "provide a detailed report on the status of their respective large commercial and industrial DR offerings…." Id., November 7, 2016 Order, pgs. 19-20.

a. Attorney General

Mr. Coppola testified that the purpose of the DR Program, peak capacity management, is achieved by the existing interruptible rate, which currently covers 61.6 MW of load. 8 TR 2293. The Company has not established why the DR Program, "with its higher incentive payments and higher administrative costs", is also needed. Id. 2293-2294. Mr. Coppola is also critical that 75% of the expenditures are paid to third-party service providers for software and management of the program. Exhibit AG-4. Further, Mr. Coppola believes the voluntary nature of the program raises doubt about the level of participation, which, in turn, will render any benefit that may result as "very marginal." Id., 2294. Accordingly, the Attorney General seeks the denial of the request to recover all costs associated with the DR Program.

b. Hemlock

Mr. Gorman characterized the DR Program "as a good first step…", but identified areas where it is lacking. 8 TR 2100-2101. The first is the capacity credit provided to customers, which Mr. Gorman should reflect the full action rate for MISO Zone 7 from the previous year, that should be readily known by customers when deciding to enter into the program and represents an avoided cost for the Company. Id., 2099-2101. Those costs for the summer of 2016 was $72/MW-day, which is the amount of the capacity credit participants in 2017 would pay under Mr. Gorman's proposal. Id., 2101. As for the energy credit, Mr. Gorman found the methodology the Company proposes, curtailed load versus a baseline energy load, unclear. In its place Mr. Gorman recommends, for the purposes of transparency, replacing the baseline variable with the "customer's average actual energy use for the four-hour period preceding the called curtailment….” Id., 2102. Further, the payment should be for the Locational Marginal Price that reflects the value of the energy during a mandatory event that triggers the curtailment, which is consistent with how FERC handles DR payments. Id. Mr. Gorman testified these modifications to the DR Program ensures the benefits that flow to the Company as a result of its customers' reduction in usage are realized by those customers. Id., 2104. Mr. Gorman also took issue with the penalty for the failure to curtail during a mandatory event, classified as a threshold of 70% of the contracted capacity delivered. Under those circumstances, the customer receives no payment for actual capacity curtailed. Mr. Gorman suggests no penalty be incurred, i.e. a customer is paid for any capacity it curtails because it is possible that the Delivered Capacity of all customers, who can curtail up to 150% of Accepted Capacity, may be sufficient. Id., 2105.

Hemlock also proposed modifications to the program besides pricing and penalties. The first is to the 30-minute advanced notice the Company requires for mandatory and voluntary events. Mr. Gorman notes that a participant in the MISO demand program is can offer its curtailment within a 12 hour period, and recommends the Company increase its notification of mandatory events accordingly, Id., 2017. The benefits of this modification is increased participation in the program, and reduced administrative costs because the Company could “enroll its portfolio of demand response curtailment in subsets joining together the amount of load that requires the same notification period.” Id. For voluntary events, Mr. Gorman recommends day-ahead notification, based on day-ahead LMP values and expected load requirements, that an event is possible, and a two-hour minimum notice, based on real-time LMP values, of an actual voluntary event.

Hemlock also argues the enrollment parameters concerning level of demand response capacity and actual curtailed load during an event set forth in the Company's contract is inappropriate. See Exhibit A-52. Specifically, Mr. Gorman contends the contract language is ambiguous concerning the methodology for payment of delivered capacity: the difference between actual demand of the customer and the baseline energy usage. Id., 2108. This provision also fails to factor a customer's expected load, which may differ from its historical load that forms the baseline, or allow enrollment of capacity for a specific production process. Id., 2108-2109. Mr. Gorman also recommended a customer be allowed to provide its demand response capacity as a firm service level, or guaranteed load drop, similar to the MISO DR provision. Mr. Gorman also suggests the contract provide protection for a customer in the event the Company fails to provide adequate notice of an event, or equipment failure precludes full performance. These changes are reflected in Exhibit HSC-11.

c. *Energy Michigan, Inc*.

Similar to Mr. Gorman, Mr. Zakem testified that, in general, the DR Program is useful if designed and managed well. However, Mr. Zakem recommended the costs of the program, which he contends is a power supply capacity resources, be removed from the distribution costs allocated to Retail Open Access (ROA) customers who are not subject PSCR costs. Id., 2729.[14]

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[14] Mr. Zakem also testified, in response to the DR Program, that MISO Zone 7 is not, and will not be, short of capacity. 8 TR 2730-2735. Assuming, arguendo, this is accurate, it has no bearing on the projected capital expenditures for the DR Program, which Mr. Zakem impliedly concedes by not arguing this purported capacity surplus requires those expenditures be denied.

As a preface, Mr. Coppola's argument that the DR Program is essentially the same as the interruptible rate disregards the fundamental difference between the two services. Mr. Morales testified to that point:

> The demand response program is a negotiated contract with customers, not a tariff. With the interruptible rate, customers pay a lower rate at all times in exchange for their agreement to have their service interrupted when needed and during specified conditions. The demand response program is incentive-based by event. Payments are made based on capacity contracted and actual load shed during each event.
>
> The demand response program also allows for participation by customers of all sizes and peak demand, extending participation to customers that are excluded from participating in an interruptible rate. The interruptible rate is a year-round program that is more appropriate for large commercial or industrial customers with a high peak demand that have the ability to shed load frequently by shifting use or switching to a generator. The demand response program is event-based and is designed to have customers curtail load less frequently and for shorter periods of time, specifically during the summer months. The structure of the demand response program, with these key differences from the interruptible rate, allows the Company to have an additional capacity resource to call on in times of high demand.
> 6 TR 877-878.

Based on the difference between the purpose and particulars of the two programs, Mr. Coppola's contention that the total expenditures for the DR Program should be denied because it is duplicative of the interruptible rate cannot be sustained.

Mr. Coppola's contention that the DR Program will not serve its purpose because it is voluntary also disregards the fact participation is established through a contract that requires the customer shed load or risk being removed from the program. Thus a customer enters the program with the full understanding that it may be called on to curtail usage and operate under the demand reduction plan, making it unlikely the entity will fail to meet its obligation and forego the benefits it receives. Finally, Mr. Coppola's contention regarding the allocation of the expenditures does not provide any basis to find that renders them unreasonable or imprudent. That the Company will use third-party providers for software platforms, licenses, service and support was explained by Mr. Morales: “The costs represent the foundation of the program, without which it could not operate.” 6 TR 879.

Based on the foregoing, the Attorney General’s contention that none of the capital expenditures for the DR Program are appropriate should be rejected.

In response to Hemlock’s modifications, Mr. Morales explained the capacity credit is derived from the market value of a MW of power in the MISO market for the Planning Year, which is unaffected by the source, including demand response. Id., 880. That price, which is published, is used by the Company in its portfolio, and thus implicates other resources used to fulfill its capacity obligations. In setting the capacity credit the Company must balance fulfilling those obligations with resources at or below market price, which benefits all of its customers, and making the benefit to DR Program customers attractive. Since Mr. Gorman’s proposal of using the MISO Zone 7 Planning Resource Auction price for the previous year as the capacity credit disregards all of the considerations the Company must legitimately make in setting that credit, it should not be adopted. Similarly, Mr. Gorman’s proposal to tie capacity payments to the LMP during curtailment would render the program economically inefficient because during a capacity emergency the price “can amount to hundreds to thousands of dollars per MWh”, which, in turn, would “needlessly drive up rates and [the Company’s] costs. 6 TR 882. Mr. Gorman’s proposed modification to setting the energy baseline disregards that the Company uses the methodology for setting demand response baselines in Attachment TT to the MISO tariff. Id., 881. Accordingly, the energy baseline used by the Company should not be changed. For these reasons, the market price the Company uses is the best indicator of the value of the energy a customer foregoes through the DP Program.

The Company contends the removal of the non-performance penalty would inhibit its ability to ensure the capacity resource is available when needed, which is the cornerstone of the program. If the Company cannot provide the capacity it bid into MISO it is subject to a confiscatory non-performance penalty, making it essential that the customers upon which that bid premised meet its obligations. Id., 883. Based on this evidence, the non-performance penalty should not be removed from the DR Program. Regarding notification, Mr. Morales testified the Company is informed by MISO of an emergency implicating mandatory curtailment anywhere between 30 minutes and 12 hours of the event, making it impossible to provide its customers with 12 hours of notice. The Company is informed of voluntary events the day before, and notifies its customers at that time, with a follow-up two hours before the event commences. Hemlock's proposed notification timeframes are impractical, and should not be adopted.

Energy Michigan's argument that ROA customers not be allocated any costs for the DR Program fails to consider the Company is not seeking to recover associated capacity and energy costs in this case, which will be addressed in the PSCR process. Rather, it is requesting recovery of the costs necessary to implement and maintain the DR Program, which will result in savings to all of the Company's customers through lower capacity and energy costs. The other aspects of Mr. Zakem's testimony do not implicate the issue in this case: whether the projected DR Program costs are reasonable and prudent.

Based on the foregoing, the Company's request to include $2.8 million for O&M costs and $996,000 in capitalized costs arising from its DR Program should be approved. See Exhibits A-49 & A-50.

7. Accumulated Provision for Depreciation

In the Application, the Company projected the accumulated provision for depreciation for the test year at $4,939,995,000, with a jurisdictional adjusted depreciation reserve amount of $4,922,858,000. See Exhibit A-7, Schedule B3, line 22 & Schedule B1, line 6, column c. Ms. Rogus testified this amount was derived from applying depreciation rates to the average of Plant-in-Service as of August 2016 and August 2017. 5TR 604. Mr. Gerken proposed an adjustment of the non-jurisdictional projection to $4,911,371,000 to account for adjustments of $28,624,000 for Utility Plant and $19,002,000 obsolete inventory. 8 TR 2551; Exhibit S-2, Schedule B3, Line 22, Column (e). Based on subsequent information revealed after the filing of the Application, the Company made a number of adjustments to its revenue deficiency, including the adjustments proposed by Mr. Gerken, resulting in a total adjusted accumulated provision for depreciation of $4,912,536,000, and a jurisdictional adjusted depreciation reserve amount of $4,895,494,000. 5 TR 627-628; Exhibit A-111.

8. Construction Work in Progress (CWIP)

Wal-Mart seeks to remove $371 million projected CWIP from the Company's rate base because it constitutes charges that paid by ratepayers for assets prior to receiving any benefits from the asset. Mr. Chriss characterized this as a violation of the “matching principle (i.e., customers should bear a cost only when they are receiving a corresponding benefit)”, which compounded when customers that pay for the asset during construction, but leave the system before that process is completed. 8 TR 2432-2433. Mr. Chriss recommends the cost be borne by investors who are compensated when the assets through rate of return when the plant is in service. This would also protect ratepayers when a project is delayed or not completed. For the test year, the Company projects $371 million for CWIP, and including this cost results in an annual revenue requirement cost of $38million to ratepayers. See Exhibits A-7, Schedule B1 & SWC-1. Wal-Mart seeks to have the CWIP removed from the rate base, or in the alternative adjust the Return on Equity to reflect the risk avoided by shareholders for these costs.

Ms. Rogus provided the Company’s position on including CWIP in its rate base:

> The Commission established the inclusion of CWIP in the calculation of projected rate base over 40 years ago in its Order dated May 10, 1976 in Case No. U-4771 (see Case No. U-4771, Final Order, Attachment A, Exhibit A-2, Schedule B1). The Michigan Filing Requirements adopted in the Commission’s Order dated December 23, 2008 in Case No. U-15895, also included CWIP as part of the calculation of projected rate base (see Case No. U-15895, Final Order, Attachment 2, Exhibit A-2, Schedule B1). Based on the Commission’s filing requirements, the Company has appropriately included CWIP in its calculation of projected rate base.
> 5 TR 626.

Consistent with the Commission’s long-time treatment of CWIP, Ms. Rogus notes the costs are for projects that will, for the most part, be “completed and closed within a year and will be used and useful within the period that rates are in effect.” 6 TR 626. Finally, Ms. Rogus explained the treatment of CWIP, and why its actual effect on ratepayers is contrary to Wal-Mart’s argument:

> The criterion for applying Allowance for Funds Used During Construction ("AFUDC") to a construction project requires on-site construction activities of more than six months duration and an estimated plant cost (excluding AFUDC) in excess of $50,000. The Commission recognizes that these longer term projects may not be used and useful over the test period and have remedied this by including an AFUDC offset in the calculation of net operating income. Theoretically, the return on the CWIP included in rate base component for these longer term projects, which increases customers' cost, will be offset by the increased income from the AFUDC offset, which will lower the customers' cost, resulting in a net effect of $0 on the customer. This AFUDC offset has also been part of the Commission filing requirements for over 40 years.
> 6 TR 626-627.

Based on the foregoing, Wal-Mart's adjustment for CWIP cannot be sustained.

B. <u>Working Capital Methodology and Calculation</u>

The Company requests Working Capital be set a jurisdictional amount of $808.778 million for the test year rate base, reflecting a $14 million reduction from the amount proposed in the Application. 5 TR 628; Initial Brief, Appendix B, pg. 1. That amount was arrived by using a balance sheet methodology:

> The starting point is the 13-month average historical December 2014 working capital shown in column (b) [of Exhibit A-7], which is first adjusted to reflect the 13-month average ending November 2015 balances shown in column (d), the most current study practical for inclusion at the time of filing. The November 2015 average balances are then adjusted to: (i) reflect a change in cash and accounts receivable financing sponsored by witness Denato; (ii) reflect changes to pension and OPEB balances based on projections sponsored by witness Kops; (iii) adjust materials and supplies related to inventory associated with the Classic 7 generating units; and (iv) adjust for accrued tax. Details for the adjustments made to calculate a normalized working capital are shown on page 2 of [Exhibit A-7].
> 5 TR 605.

The balance sheet methodology to calculate Working Capital has been approved by the Commission in previous cases. Id., 605. Consistent with the Commission's holding in U-17735, the Company has removed temporary cash investments, which was maintained at a 1% of revenues, from the cash accounts balance component of its Working Capital. Id., 479.

1. Attorney General

The Attorney General takes issue with the Working Capital projection, and recommends a $34.6 million reduction to reflect a lower cash balance level, and a higher level of interest payable. 8 TR 2330; Exhibit AG-14. Mr. Coppola testified to the reduction to cash balance is warranted because the level used by the Company, approximately 1% of revenues, is not necessary given the "large bank lines of credit and access to the commercial paper market…" that can be used. Id., 2331. The interest adjustment reflects Mr. Coppola's view that the Company's "ambitious capital program…" has increased long term debt by 11% from the historic 2015 level and the projected test year. Id. Accordingly, Mr. Coppola recommends an 11% increase in accrued interest, and a corresponding $4.6 million reduction in Working Capital.

Mr. Denato testified that the reduction in the Company's cash balance the Attorney General proposes would leave it with $14 million for the test year, which is 0.3% of electric revenues. 5 TR 490. This reduction in liquidity would expose the Company to inadequate liquidity on hand for operations, and potentially expose it to the volatility in capital market, and corresponding costs, the cash balance level had to be raised. Id., 490-491. Mr. Denato testified the $30 million increase of cash balance, representing 1% of revenues, the Company seeks is necessary for operation considerations. In addition, Mr. Denato testified the cash balance the Company proposes also reflects the seasonality of the Company's cash flows, ability to obtain lower interest rates for bond financing and refinancing, and its "large capital expenditure program…" requires liquidity in the event obtaining long-term capital from markets is delayed. Id., 491. The 1% of revenues cash balance is also standard in the industry. Id. Based on this evidence, the Company has established the $3.4 million in its cash balance, representing 1% of revenues, is reasonable and prudent.

C. Total Rate Base

The Company requests rates set at a jurisdictional total base rate of $10,187,000,000. Exhibit A-110; Initial Brief, pg. 1. That amount consists of:

Total Plant Utility	$	14,302,644,000
Accumulated Depreciation		(4,895,494,000)
Net Plant Utility	$	9,407,150,000
Retainers and Customer Advances		(28,837,000)
Working Capital		808,778,000
Total Base Rate	$	10,187,090,000

For the reasons discussed above, the record indicates that the Net Plant Utility should be reduced by $57,235,000 based on the following adjustments:

1. $12,927,000 - Capital Capacity Program
2. $29,219,000 – Grid Modernization Program
3. $4,489,000 – Smart Grid/AMI
4. $10,600,000 – PEV Infrastructure Program

These capital expenditure adjustments translate to a Total Base Rate of $10,217,181, and a jurisdictional Total Rate Base of $10,171,612. See Appendix B.

V. RATE OF RETURN AND CAPITAL STRUCTURE

The Company seeks a rate of return of 6.18% be used to set rates in this case. Exhibit A-90; Initial Brief, Appendix F. This rate of return is based on the weighted average costs of the sources of capital comprising the capital structure. The weighted cost for each component of the capital structure is determined by multiplying the percentage ratio for that component by the cost rate for that component. The weighted cost rates for each component are then added to determine the overall rate of return. The Company is proposing the authorized Return on Equity (ROE) be set at 10.70%, which is 40 basis points higher than the rate of return authorized by the Commission in U-17735. Staff recommends an overall rate of return of 5.90%, and an ROE of 10.00%. The Attorney General's proposed overall rate of return is 6.01%, and an ROE of 9.75%. ABATE recommends an ROE of 9.30%. Walmart did not proffer a specific ROE However, it notes that in 2016 the ROE for eight similarly situated public utilities was 9.53%, which along with the significant impact on customers and the reduced risk in Michigan's regulatory framework, renders the Company's proposed 10.70% ROE excessive.

A. Test Year Capital Structure

Mr. Denato testified to the capital structure the Company is proposing:

> I am recommending that the capital structure shown on Exhibit A-9 (AJD-1), Schedule D-1 be used in this case. This represents the actual capital structure as of December 31, 2015, adjusted for the projected changes in debt, equity, and deferred income taxes through the end of the test year ending on August 31, 2017. The development of the capital structure on a ratemaking basis is shown in columns (b) through (d). The equity ratio as a percentage of permanent capital is 53.06%. The equity ratio on a ratemaking basis is 40.93%.
> 5 TR 461.

No other party recommended a different capital structure for the test year, and thus the Company's proposal is adopted.

1. <u>Capital Structure Component Balances</u>

a. Common Equity

The Company initially projected an average common equity balance of $6.129 billion. Exhibit A-9, Schedule D1a, pg. 2. Mr. Donato provided the methodology utilized to arrive at this amount. 5 TR 462-466. Subsequently, the projection was set at $6,083,846,676. Id., 486; Exhibits A-90 and A-91. Although it initially sought a reduction, Staff now accepts the Company's projected common equity balance of $6.083 billion, which also changes its permanent common equity balance percentage from 52.4% to 52.87%, and overall cost of capital from 5.86% to 5.90%. Initial Brief, pg. 52, Dkt #363. The Attorney General's recommended adjustment to this balance is discussed below.

b. Long-Term Debt

For the test year, the Company projects a $5.385 long-term debt balance. 5 TR 465; Exhibit A-9, Schedules D1, & D1a. Staff concurs with this projection, and it is adopted.

c. Short-Term Debt

For the test year, the Company projects a $165 million short-term debt balance. 5 TR 466; Exhibit A-9, Schedule D1 & D1a. Staff concurs with this projection, and it is adopted.

d. Deferred Federal Income Tax

For the test year, the Company projects a $3.207 billion deferred tax balance. 5 TR 469; Exhibit A-9, Schedule D1 & D1a. Staff concurs with this projection, and it is adopted.

e. Other Capital Structure

The Company and Staff used balances for preferred stock and Job Development Investment Tax Credit (JDITC) corresponding to balances in the historical period, with components for JDITC based upon the allocation of long-term debt, preferred stock, and common equity. 5 TR 470; 8 TR 2458; Exhibit A-90 (AJD-10); Exhibit S-4, Schedule D1.

The Attorney General recommends a change to the capital structure balances to reflect an upward adjustment of $353 million to long-term debt, and a corresponding downward adjustment to common equity. 8 TR 2336; Exhibit AG-15. The result is a capital structure with 50% common equity, as opposed to the 53.06% proposed by the Company, and 50% of debt and preferred stock. Mr. Coppola noted the Company's stated goal is to maintain a capital structure with a common equity ratio of 50%, which is what he is proposing, and should be adopted for the following reasons:

> First, the higher equity capital proposed by the Company unnecessarily increases capital costs to customers because common equity is a much higher cost source of capital than debt.
>
> Second, the 53.06% level of equity is high compared to the average of the peer group selected by the Company which is 48.8% (see Exhibit AG-18, column (c)).
>
> Third, the current high level of common equity of the Company is the result of its parent company, CMS Energy, borrowing debt capital and investing the proceeds as equity into the Company. The Commission should recognize that the common equity of CMS Energy at March 31, 2016 was $4.1 billion. However, the Company's common equity level is $5.4 billion in the 2015 historic test year (32% greater) due to these so-called common equity injections which originate from debt issued by CMS Energy. Most of this disparity has occurred within the past 10 years. At December 31, 2005, the Common Equity balance of CMS Energy was $2.3 billion and the CECo Common Equity balance was $2.8 billion which is a difference of $0.5 billion. Since that time the difference has grown to $1.6 billion. This clearly shows that the incremental equity capital infused into CECo from CMS Energy of approximately $1.0 billion is not equity capital but primarily debt disguised as equity. The Commission should not

> allow the Company to perpetuate this scheme by constantly increasing the percent of equity capital in the permanent capital structure.
>
> Fourth, the Common Equity level proposed by DTE Electric in its case U-18014 now pending before this Commission is at the 50% level and I consider CECo's electric business to be highly similar to DTE Electric. Utilizing a 50% common equity level to set rates in this case brings the Company's equity level in line with other similar companies while minimizing costs to customers.
> 8 TR 2337-2338.

In response, the Company notes that while its goal is to maintain a common equity ratio of approximately 50%, it is not a strict benchmark and fluctuations are expected. 5 TR 487. As it pertains to this case, the common equity ratio the Company is projecting for the test year reflects the "significant capital investments" it plans to make over the next 5 years. Id., 464. To that end, the Company must set the common equity balance and ratio to maintain its credit rating and be positioned to withstand market fluctuations that could inhibit those plans. Id. The Company is also able to prefund its debt maturities at the current low interest rates under its projected 53.06% ratio. Id. In that regard, Mr. Denato noted:

> [C]ertain credit rating agencies (e.g. Moody's Investors Service ("Moody's")) include securitization debt when calculating debt to equity ratios. Certain credit rating agencies (e.g. Standard and Poor's ("S&P")) also consider items such as Power Purchase Agreements ("PPA"), benefit obligations, and leases as "debt" when calculating debt to equity ratios. Incorporating the projected equity infusions in 2016 and 2017 in the common equity balance enables the Company to maintain reasonable ratios after such adjustments. The Commission recognized that these circumstances support the need for a slightly higher equity ratio in Case No. U-17735, the Company's last electric rate case.
> 5 TR 564-565.

As it pertains to the Attorney General's proposed 50% ratio, Mr. Denato notes mechanically setting the level would diminish the Company's credit ratings and result in higher costs for its ratepayers. Further, Mr. Coppola's contention that the ratio for other regulated utilities is 48.8% is inaccurate given the actual average equity ratio as a percentage of permanent capital in 2015 is 53%. Id., 488; Exhibit A-92. Mr. Coppola arrived at his ratio by using data concerning the parent companies of those utilities that "may be distorted by other, non-regulated balance sheet items. Id. Mr. Coppola also bases the proposed ratio on his contention that the Company's parent company, CMS Energy, is disguising its borrowed debt as equity in the regulated utility. However, beyond noting the levels of common equity at the two entities over the past 10 years, Mr. Coppola does not provide any other reasons to support his contention. Specifically, that the 2016 and 2017 equity infusions from CMS Energy were anything more than what Mr. Denato claims: the parent company acting to ensure the Company has sufficient capital as it undertakes its 5-year infrastructure investments. Similarly, Mr. Coppola's use of DTE Electric Company's projected common equity level in its pending rate case is not, standing alone, a sufficient basis to accept his recommendation. Rather, the proper inquiry is whether the projected level is reasonable and none of the arguments the Attorney General has raised on this point are sufficient to find the Company's equity ratio is unreasonable.

Based on this record, the Company has established the 53.06% equity ratio it proposes is, in light of its planned investments over the next 5 years and the corresponding need to maintain its credit ratings, reasonable. Concomitantly, the Company's projected capital structure should be adopted. See Exhibit A-90, Initial Brief, Appendix F.

B. Cost Rates

1. Return on Common Equity

a. The Company

In this proceeding the Company is seeking an authorized ROE of 10.70%, which represents a 40 basis point increase from the 10.30% level set in U-17735.[15] As a general matter, Mr. Rao testified the proposed ROE reflects the current state of the economy and capital markets, will allow the Company to attract sufficient capital to finance its capital expenditure programs, reflects the risk profile of the Company's proxy group, and is consistent with modeling of the cost of equity. 5 TR 178; Exhibit A-9. Mr. Rao also testified to the general perception that Michigan has a favorable regulatory environment, and the Company has a good reputation. Id., 179. Integral to both of these factors is setting a reasonable ROE, which will allow the Company to continue raise capital at attractive prices and enhance customer service. This is especially true in light of the current environment of volatile markets that has caused investor "flight to quality" equities. Id., 179-181. All of these factors must be included in conjunction with traditional methodologies often used in utility cost of capital determinations, but are premised on relatively stable market conditions and thus prone to understatement, to accurately ascertain investor expectations. Id., 182.

Mr. Rao based the recommended ROE on a proxy group of publicly traded electric utilities that met the following criteria:

> [C]ompanies that are currently classified as electric utility companies by the Value Line Investment Survey ("Value Line"). Then, in addition, the company had to: (i) be paying current common stock dividends; (ii) have

[15] A 10.30% ROE was approved in by the June 7, 2012 Order in Case No. U-16794, and then again in the May 15, 2013 Order approving a settlement agreement in Case No. U-17087.

> bonds rated at or above a minimum investment grade of Baa3 by Moody's Investor Services ("Moody's") and BBB- by S&P; (iii) have approximately 45% or more of its operating revenues from regulated electric operations; (iv) have Net Plant greater than $5 billion; and (v) not be a company that was planning to merge with another company.
> 4 TR 184

Under this criteria, Mr. Rao selected 18 proxy group companies, to which he added DTE Energy based on its similarities to the Company. Exhibit A-9, Schedule D5, pg. 1. From these 19 companies, Mr. Rao selected a subset of 5 companies with less than $10 billion Net Plant that he deemed are most similar to the Company and are used in some of his modeling. Exhibit A-9, pg. 1.

In conjunction with the non-qualitative measures discussed above, such as investor perception of Michigan's regulatory environment, Mr. Rao factored a number of national and international economic indicators and outlooks into his risk analysis. 4 TR 196-207. Another measure of risk is the Company's "significant capital investment", projected at $11 billion over the next 10 years, which Mr. Rao inveighs against setting an ROE too low and thereby hindering the Company's ability to attract capital. Id., 207-209, 214. For qualitative measurements, Mr. Rao used Capital Asset Pricing Model ("CAPM") and Empirical Capital Asset Pricing Model ("ECAPM"), a Risk Premium analysis, the Discounted Cash Flow ("DCF") model, and a Comparable Earnings Analysis. See 4 TR 184-195. In light of low interest rates, which Mr. Rao testified have a greater than normal impact on utility stocks, a risk-free rate based on the average income return of Long-Term Government bonds from 1926-2014 was used for the CAPM, ECAPM, and Risk Premium analysis. Id., 186-190. The results of Mr. Rao's study are:

Proxy Group/Utility	Average		Median
Results			
Capital Asset Pricing Model w/ Historical Risk-Free Rate	10.27%		10.32%
Empirical Capital Asset Pricing Model w/ Historical Risk-Free Rate	10.65%		10.70%
Risk Premium Analysis Over Utility Bonds	10.93%		10.97%
Discounted Cash Flow Model	10.35%		9.59%
Comparable Earnings Analysis	10.15%		10.06%
Recommended Cost of Equity Range for Consumers Energy		10.30% - 10.90%	
Recommended Ratemaking Cost of Equity for Consumers Energy:		10.70%	

Exhibit A-9, Schedule D5, pg. 15

Mr. Rao testified his recommended ROE is:

> [C]onsistent with both my qualitative and quantitative analysis. The current environment of equity volatility, slowing global growth, and extreme uncertainty with regards to the timing and extent of a further rise in interest rates all support increasing the ROE. As I mentioned earlier in my testimony, the Federal Reserve has begun its rate tightening and the consensus from the economic and financial forecasting community is that interest rates will continue to rise into the future. There is a clear possibility that when the Federal Reserve completes its scaling back of its supportive monetary policy, interest rates will again make a dramatic jump to more normal levels. This risk needs to be incorporated in determining the appropriate ROE for the Company. The quantitative analysis I have performed incorporates this risk and supports an ROE that is higher than the current level. Although a crisis in China or Europe or other global economic/monetary factors might keep U.S. Treasury rates low from time to time, the same should not be construed as the reduction in cost of capital, but rather an indication of flight-to-quality or risk-averse nature of investors which leads to higher risk spreads and higher cost of capital for corporations. Based on these factors and my assessment of the business climate, investor views of the regulatory and economic environment, and my professional judgment, I am recommending that the Commission adopt a ROE for Consumers Energy's electric business at 10.70%. 4 TR 211

b. Staff

Staff proposes an ROE of 10.0% by applying the Discounted Cash Flow (DCF) Model and Capital Asset Pricing Model (CAPM) to the proxy group of 12 publicly traded electric utility companies, a Risk Premium analysis, and the Company's existing ROE, proposed ROE, and commission-approved ROEs in other states. 8 TR 2456-2455.

Mr. Megginson testified the proxy group of 12 companies was formulated using five criteria:

> 1) each utility had to have net plant greater than $3.5 billion but less than $20.0 billion to better compare in size and footprint to Consumers Energy's electric division; 2) each company had to derive approximately 50% or more of its revenues from regulated electric service; 3) each utility had to have an investment grade rating within three notches from that of Consumers Energy from the two primary rating agencies Standard &Poor's (S&P) and Moody's; 4) each company had to currently be paying dividends to shareholders; and 5) Staff attempted to exclude companies that were currently involved in mergers or major corporate buyouts. [16]
> 8 TR 2464; see also Exhibit S-4, Schedule D-5, pg. 2.

Mr. Megginson testified that under the DCF model, which is widely used to estimate equity investor's return demand, the average adjusted ROE for the proxy companies is 8.68%. Id., 2467. That rate was "determined using the constant model, which adds the average dividend yield to the expected growth rate but adjusts the dividend yield by a semi-annually compounded projected growth rate based on the formula DCF = (D/P)*[1 + 0.5g] + g. The semi-annual compounding model is the model used by FERC and is a reasonable to use when performing a DCF analysis on a group of comparison companies. Id. The inputs for CAPM, which compares a utilities risk to overall market risk, is a risk-free rate of 3.10% derived from Value Line's long-term Treasury bond

[16] Four companies Staff used in the proxy group in previous cases were excluded in this case because they involved in merger or acquisition activities. 8 TR 2464.

forecast for 2017, a beta of 0.77 and also derived from Value Line, and a 6.30% market return rate. Id., 2469-2471. Mr. Megginson calculated an average ROE of the proxy group under CAPM of 7.96%.

The third methodology Staff used is the Risk premium approach, which Mr. Megginson testified:

> [I]ncorporates the spread from historical electric utility realized stock returns and historical composite utility bond yields and adds this spread to current long-term utility bond yields to obtain an investor's current reasonable required rate of return.
> 8 TR 2474.

Under this method, Mr. Megginson used:

> [T]he Electric Utility Realized Market Return Average from 1932 through 2015, compared with the Single-A Realized Public Utility Bond Yield Average over the same period. Mergent Public Utility Manual & Bond Record provided complete market return and bond yield data until 2002. Therefore, in order to obtain utility market data for 2003 to 2015, Staff used data from the Dow Jones Utilities index as shown on the bottom of Exhibit No. S-4, Schedule D-5, page 10 of 14.
>
> The average electric market return over that period was 10.94% and the average A-rated composite utility bond yield was 6.49% over the same period. Subtracting the bond yield from the market return yielded an historical spread of 4.45%, as shown on Schedule D-5, page 11 of 14. From a forward looking perspective, I also included a survey of academics, analysts and companies and their estimate of projected equity spreads over bond yields. The information was taken from a 2015 Edition of Equity Risk Premiums (ERP): Determinants, Estimation and Implications [footnote omitted] by Aswath Damodaran, professor at New York University's Stern School of Business. The average projected spread was 5.37%.
> 8 TR 2474-2475

The bond yield data was derived from:

> [C]ertain Value Line April 20 through June 22, 2016 long-term utility bond yields and obtained an average 3.97% yield for A-rated bonds and 4.42% for BBB-rated bonds. Adding these current bond yields to the historical spread of 4.45% produced a rate of return estimate of 8.42% for the A-rated bond and 8.87% for the BBB-rated bond. Adding the current bond

> yields to the forecasted survey projections produced 9.34% results for A-rated bonds and 9.79% results for BBB rated bonds.
> 8 TR 2475.

Based on the foregoing, Mr. Megginson determined an ROE range of 8.42% to 9.79% under the Risk Premium approach. The final factor, commission-authorized ROE in other states averaged 9.88%. 8 TR 2475; Exhibit S-4, Schedule D-5, pg. 13.

Staff's models, along with the other factors, produced an ROE range of 9.00% to 10.00%. When taking into account the Company's current ROE of 10.30%, Staff recommends the REO in this case be set at 10.00%. Id., 2476; Exhibit S-4, Schedule D-5, pg. 14.

c. ABATE

ABATE recommends an ROE of 9.30%, which is the approximate mid-point of the range determined by Mr. Walters: 8.90% to 9.60%. Mr. Walter prefaced his testimony of the methodology he utilized to arrive at his recommendation by noting authorized ROE rates have been in steady decline for the 10 years, and now average approximately 9.6% to 9.7%. 8 TR 1876-1877. This decline follows the corresponding decline in capital market costs over the same period, and has had no effect on a regulated utilities credit ratings, which in 2014 and 2015 have had more upgrades than downgrades, or ability to attract capital to fund programs. Id., 1878-1880. Mr. Walters also noted that utility common stock is in the midst of a period of "robust valuation", which is another indication that utilities have access to capital at costs that are "relatively low." Id., 1881; Exhibit AB-3. Mr. Walters indicates the Commission should "carefully weigh all this observable market evidence in assessing a fair…" ROE in this case. 8 TR 1881.

To determine the ROE, Mr. Walters used “a constant growth Discounted Cash Flow (“DCF”) model using consensus analysts’ growth rate projections; (2) a constant growth DCF using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Risk Premium model; and (5) a Capital Asset Pricing Model (“CAPM”).” 8 TR 1883-1884. For the proxy group, Mr. Walters relied on the same 19 companies used by Mr. Rao, except two that are involved in a merger/acquisition, as reasonable approximations of the investment risk in the Company. Id. 1884-1886; Exhibit AB-4.

Mr. Walters provided a detailed analysis of the inputs in each of the three DCF models, and the reasoning behind them. Id., 1886-1899; Exhibits AB-6, AB-8 & AB-9. Those studies support an 8.70% ROE, which Mr. Walters primarily based on the DCF Constant/Sustainable Growth Model that he characterized as a “reasonable high-end DCF return estimate. 8 TR 1899. For the Risk Premium Model, Mr. Walters assigned more weight to the high-end risk premium estimates primarily because of low interest rates coupled with recent upward movement of utility yields. He calculated the Treasury bond risk premium at 9.50% and the utility bond risk premium at 9.65%, and estimated the ROE under this methodology at its approximate mid-point, 9.60%. Id., 1907. For the CAPM model Mr. Walters used a projected 30-year Treasury bond yield for the risk-free rate, the proxy group average Value Line beta estimate, and a forward-looking estimate and expected return on the market for the market risk premium. Id., 1907-1912. Based on these inputs, the CAPM projects a ROE of 7.74% to 9.04%. Id., 1912; Exhibit AB-18. When considering risk premiums in the current market, the CAPM estimates the Company’s current market cost of equity at 9.00%. 8 TR 1913.

Mr. Walters recommends a ROE of 9.3%, which is the mid-point of the three models, and reflects:

> [O]bservable market evidence, the impact on Federal Reserve policies on current and expected long-term capital market costs, an assessment of the current risk premium built into current market securities, and a general assessment of the current investment risk characteristics of the electric utility industry, and the market's demand for utility securities.
> 8 TR 1913.

This recommended ROE, along with the capital structure and proposed embedded debt cost, will not adversely affect the Company's investment grade bond rating. 8 TR 1914-1917.

d. The Attorney General

On behalf of the Attorney General, Mr. Coppola also utilized the DCF Method, CAPM, and a Risk Premium Approach to determine his recommended ROE of 9.75%. Id., 2339, 2314; Exhibits AG-15 and AG-16. Mr. Coppola also used Mr. Rao's proxy companies, except for one that has undergone a significant in reported earnings since 2012. 8 TR 2342. Mr. Coppola testified to his conclusions based on the modeling along with his assessment of the economy and approaches of commissions in other states:

> The ranges of returns for the industry peer group are from 8.56% at the low end, using the CAPM approach and 9.36% at the high end using the Equity Risk Premium approach.
>
> As explained earlier in my testimony, I give more weight to the DCF method as a more reliable approach to estimating the cost of equity. In this regard, on line 4 of Exhibit AG-16, I have calculated a weighted return on equity of the three methodologies using a 50% weight for DCF and 25% for each of the other two methods. The result is a weighted return on equity of 8.88% for the average of the industry peer group. However, I have increased this number up to a 9.75% return of common equity for CECo for the reasons explained below.

> First, although the industry peer group return is an appropriate check on the reasonableness of my conclusion, it may not incorporate the unique risks and circumstances that exist with CECo's electric business and how investors perceive those risks—in particular, serving a territory that is highly dependent upon the automotive industry. Second, as mentioned above, the extent to which investors anticipate higher interest rates is uncertain. As such, while the cost of common equity under the DCF approach is an accurate assessment of expectations for the forecasted test year, the higher interest rates assumed in this case may very well produce a different result should such higher interest rates become a reality. In this regard, a potential 10% correction in utility stock prices due to higher interest rates would produce a 0.40% increase in the cost of capital under the DCF approach.
>
> Furthermore, I understand that the Commission may be reluctant to set an ROE for the Company at the true cost of equity of 8.88%. As shown in Exhibit AG-20, regulatory commissions around the country have granted an average ROE of 9.60% to electric utilities during 2015 and the first quarter of 2016. In fact, all of the reported ROE decisions in electric utility rate cases reported by "Regulatory Focus" during this timeframe are below 10% except for decisions in Michigan and Wisconsin. [footnote omitted]. Therefore, my recommend ROE rate of 9.75% in this case is reasonable and fair, if not generous, as a gradual transition to the true cost of equity.
> 8 TR 2353-2354.

e. Wal-Mart

In regards to the ROE, Wal-Mart offered Mr. Chriss, who testified the Company's recommended ROE of 10.70% "presents a significant impact to customers." 8 TR 2425. Further, Mr. Chriss characterized the recommendation as excessive relative to the average ROEs approved by other state commissions for the period of 2013-2016, which ranges from 8.72% to 10.95%, with a median of 9.75%. 8 TR 2434-2435; Exhibit SWC-4. [17] The recent trend for commission approved ROEs for vertically integrated utilities has been going down, with 8 ROEs set at less than 9.53% or less in 2015 and a portion of 2016. However, in Michigan the average Commission approved ROE is

[17] Mr. Chriss, along with other parties, contend that if the Company's request for rate mechanisms is approved in this case, the ROE should be reduced to account for the resulting impact to revenue levels and earning assurances. Those mechanisms are addressed below.

10.25% for 2013-2016, which is 40 basis points higher than the rest of the country. 8 TR 2436-2437. While Mr. Chriss did not offer a recommended ROE in this case he testified the "Commission closely examine…" the Company's request so as to minimize the impact to ratepayers. Id., 2437.

2. Recommended ROE

In the Company's last rate case, along with the Parties in their respective briefs in this case, the Commission noted the long-standing principle that the rate of return for a public utility must be set at a level that ensures investors have confidence in the soundness of the enterprise, but at the same time is not unnecessarily burdensome on ratepayers.[18] However, the Commission also noted the determination "is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use."[19] In this case, the Parties recommend an ROE ranging from the 10.70% the Company seeks, the 9.30% ABATE proposes, with Staff at 10.00%, and the Attorney General at 9.75%, falling between those points.

The inquiry begins with the Company's recommended ROE of 10.70%, which is a 40 basis increase from its current 10.30%. That rate was reaffirmed by the Commission last year because a 10.30% ROE "will best achieve the goals of providing appropriate compensation for risk, ensuring the financial soundness of the business, and maintaining a strong ability to attract capital." Case No. U-17735, November 19, 2015 Order, pg. 47. The Company has not provided any substantive evidence that

[18] *In re: Consumers Energy*, Case No. U-17735, November 19, 2015 Order, pgs. 32-33, citing *Bluefield Waterworks & Improvement Co v Public Service Comm of West Virginia*, 262 US 679; 43 S Ct 675 (1923); *Federal Power Comm v Hope Natural Gas*, 320 US 591; 64 S Ct 281 (1944).
[19] *Township of Meridian v City of East Lansing*, 342 Mich 734, 749; 71 NW2d 234 (1955).

those goals have, in the intervening period, been unattainable. Mr. Rao testified the increased ROA is necessary given current market conditions and the Company's need to attract capital for its significant investments in the coming years. However, as Mr. Walters indicated, the regulated gas and electric utility industry has undergone "an elevated and record setting capital expenditure cycle", going from $70 billion in 2011 to a projected $115 billion in 2016. 8 TR 1938-1939. Thus the Company's increased capital expenditures are in line with the industry and do not, standing alone, warrant a 40 basis point increase in its ROE. Mr. Rao also does not provide any substantive basis to conclude current economic conditions have undergone, or will undergo, any significant changes that warrant a 10.70% ROE.[20] Rather, as Mr. Walters' testimony establishes, current economic conditions have not diminished the regulated utility industry in regards to investment risks, credit standing, and stock price performance. Id., 1866-1870. Similarly, the consensus outlook for the industry is it will remain stable because of the expectation of continued low capital costs. Id., 1870-1874.

Mr. Walters also raises valid points concerning the reliability of the models Mr. Rao utilized to arrive at his recommended ROE. For example, the top end of Mr. Rao's CAPM analysis, 10.27%, derives from a historical risk free rate and risk premium. However, the bottom of the range, 8.77%, is projected and factors in current cost of equity, which is declining. Id., 1920-1921. Mr. Walters notes the unreliability of the historical rate is exemplified by the inclusion of the historical average of 30-year Treasury yields, 5.07%, as opposed to the current yields, 2.57% to 2.65%, and

[20] Mr. Walters' point that should the cost of capital increase to the extent Mr. Rao suggests while the rates are in effect, the Company can file a rate case, an option not available to ratepayers when the cost of capital declines, is well-taken. 8 TR 1921.

projected yield of 3.15% in 2017.[21] Id., 1921-1922. Mr. Rao also used historical averages, as opposed current data and projections, in his Risk Premium analysis that also skewed the results and rendered the average ROE of 10.93% unreliable. Id., 1928-1929.

Staff also makes a compelling argument concerning the Company's modeling, noting the use of an adjusted beta in the ECAPM analysis, as opposed to the unadjusted raw beta, does not correct deficiencies as Mr. Rao claims. See 4 TR 239-242. Rather, it produces higher results, which is what the Proposal for Decision (PFD) in U-17335 found at pg. 86. See 8 TR 2473-2474. While the Commission did not adopt the PFD's recommended ROE of 10.00%, it also rejected the Company's proposed ROE, based in part on Mr. Rao's ECAPM analysis. In any event, Mr. Walters' explanation of the effect of an adjusted beta on the reliability of the ECAPM is reasonable:

> If an adjusted beta is used in the ECAPM, you double-count the adjustment to the return on equity estimate. Value *Line*'s adjusted beta creates the same impact on a CAPM return estimate as the ECAPM. Specifically, *Value Line*'s beta adjustment when used in a traditional CAPM return estimate, will increase a CAPM return estimate when the beta is less than 1.0, and decrease the CAPM return estimate when the beta is greater than 1.0. Therefore, an ECAPM with a raw beta produces the same impact on the CAPM return estimate as does a traditional CAPM using an adjusted beta estimate.
>
> Importantly, I am not aware of any research that was subjected to peer review that supports Mr. Rao's proposed use of an adjusted beta in an ECAPM study. Therefore, Mr. Rao's proposal to use an "adjusted" beta, such as those provided by *Value Line*, in an ECAPM analysis is not based on sound academic principles, is not supported by the academic community, and should be rejected. Further, using an adjusted beta in an

[21] The unreliability of the historical risk free rate and risk premium was exemplified in U-17735, where Mr. Rao used historical data to project an increase of interest rates to 4.3% by the end of the 2nd quarter in 2016, while the actual interest rate 2.42%. 8 TR 1921. Other near-term projections in the CAPM analysis using historical averages in U-17735 were also significantly over-stated. Id., 1922-1923; Exhibit AB-16.

> ECAPM analysis, as Mr. Rao proposes, double-counts the increase in the CAPM return estimates for betas less than 1.0, and correspondingly would decrease the CAPM return estimates for companies that have betas greater than 1.0. Since utility companies have betas less than 1.0, Mr. Rao's application of an ECAPM with adjusted beta estimates overstates a CAPM return estimate for a utility company.
> 8 TR 1926-1927

When using the raw beta estimate, Mr. Walters arrived at an ECAPM estimate range of 8.40% to 8.95%, with an approximate mid-point of 8.70%. 8 TR 1927; Exhibit AB-20. This is a significant difference between the Company's 10.65% ROE for the proxy companies under its ECAPM analysis.

Based on this record, and for the reasons discussed above, the Company's recommended ROE of 10.70% ROE is excessive.

This leaves the issue of what ROE strikes the proper balance between the need to attract capital and at the same time ensure ratepayers are not unnecessarily burdened.[22] As noted, the record does not indicate the Company's current ROE of 10.30% has in any manner affected its ability to attract capital. To the contrary, the Company's credit rating remains strong, and the current low interest rates has allowed for lower debt costs. However, the Company's contention that if the ROE is set to low its positive financial outlook will be threatened obviously bears consideration.

The 9.75% ROE proposed by the Attorney General, a 55 basis point reduction from the current rate, and the 9.30% ROE proposed by ABATE, a 100 basis point reduction would, as Mr. Rao contends, be harmful to the Company's credit ratings and financial metrics. See 4 TR 247-267. Specifically, a reduction of the magnitude proposed by these parties would, as Mr. Rao testified, diminish:

[22] In striking this balance, Mr. Walters' point that should the cost of capital increase while the rates are in effect, the Company can file a rate case, an option not available to ratepayers when the cost of capital declines, is well-taken. 8 TR 1921.

> (1) the consistent, constructive regulatory environment over the past several years has had a favorable impact on the Company's debt credit ratings; (2) higher credit ratings (combined with lower Treasury rates) has in fact translated into a lower cost of debt, with the related cost savings passed along to customers; and (3) reducing the Company's ROE to 9.3%, as recommended by Mr. Walters, would send a negative signal to investors, analysts, and credit rating agencies who are looking for a long, consistent, and constructive track record from the Commission. Lowering the Company's ROE would jeopardize the good progress made in recent years, reflected in the above chart, and would be harmful to customers.
> 4 TR 262.[23]

Based on this evidence, the ROE recommended by the Attorney General and ABATE should not be adopted.

As for Staff's proposed 10.00% ROE, Mr. Megginson set the ROE range at 9.00% to 10.00% based on DCF modeling which had an average of 8.68%, CAPM modeling which had an average ROE of 7.96%, a Risk Premium analysis that had a range of 8.42% and 9.79%, and commission-approved ROEs in other states which averaged 9.88%. See Exhibit S-4, Schedule D-5, pg. 14. Finally, the proxy group's average authorized ROE is 10.12%, despite an average credit rating below the Company's rating S&P rating (A), and Moody's rating (A1). 8 TR 2465; Exhibit S-4, Schedule 5, pgs. 2-5. Mr. Megginson testified the 10.00% ROE would ensure the Company is still able to access credit markets on favorable terms, allow it to proceed with its capital investments, is consistent with the proxy group average, and at the same time not unduly burden ratepayers. Further, Mr. Megginson notes Staff's ROE factors in the "beneficial" provisions, in the sense it favors utilities and its investors, of Public Act 286: projected test years, self-implementation, a decision on a rate increase in 365 days, and the retail choice limit of 10% of the Company's total sales. 8 TR 2477,

[23] The chart referenced in this testimony depicts the improvement in the Company's credit rating and decreased cost of long-term debt since the 10.30% ROE was set in June 2012 (U-16794), and continued in May 2013 (U-17087) and November 2015 (U-17735). 8 TR 261.

quoting Case No. U-17735, Proposal for Decision, pg. 88.[24] Mr. Megginson's conclusions are well-supported and well-reasoned.

As noted, the Company's proposed ROE is excessive, while the rates proposed by the ABATE and the Attorney General raises an unacceptable risk of diminishing the Company's favorable credit ratings and financial metrics. Based on those ratings and metrics, the current ROE of 10.30% is proving to achieve the goal of allowing for adequate compensation for risk, ensuring the continued financial soundness of the business, and attracting capital. See U-17735, November 19, 2015 Order, pg. 47. Staff has established that setting the ROE at 10.00% will not inhibit the Company from continuing to meet those goals, while at the same time reducing the burden on ratepayers. Therefore, it is recommended the authorized ROE should be set at 10.00%.

3. Long-Term Debt

In its Application, the Company projected its long-term debt cost rate at 5.06% based on a projected 6.00% interest rate on a $550 million new debt issuance in August 2016 and a $750 million new debt issuance in July 2017. 5 TR 471; Exhibit A-9, Schedule D1, line 1, column (e), and Schedule D 2. In response, and based on published forecasts for 30-year Treasury Bond rates, Staff projected a 4.20% interest rate for the August 2016 issuance and 4.80% for the July 2017 issuance. 8 TR 2458-2459. These rates reduced the projected long-term debt cost rate to 4.87%. Exhibit S-4, Schedule D1. The Company accepts the lower interest rate for both new debt

[24] Mr. Megginson also testifed the recovery mechanisms proposed in this case is another instance of the Company minimizing its risk, and if either are approved the 10.00% ROE "is not only reasonable but is generous." 8 TR 2478.

issuances, along with the 4.87% long-term debt rate, and requests the Commission adopt that rate. 5 TR 483; Exhibit A-90.[25]

4. Short-Term Debt

The Company forecasted a short-term debt rate of 3.22% by applying the projected London Interbank Offered Rate (LIBOR) rate to its forecast of the outstanding average short-term borrowing under its commercial paper facility. Exhibit A-9, Schedule D3, page 2. Staff contends this rate should be calculated on the Company's commercial paper rate instead of the LIBOR rate. 8 TR 2460. Staff also applied the Company's commercial paper rate to the test year Renewables Liability balance. 8 TR 2460. Both adjustments, which the Company accepts, results in a short-term debt cost rate of 2.47%. See 5 TR 483, 8 TR 2460; see also Exhibit S-4, Schedule D-1; Exhibit A-90, line 5, column (e); Exhibit S-4, Schedule D-1.

5. Other Cost Rates

Both the Company and Staff agree to a 4.50% cost rate for preferred stock, and the cost rates for long-term debt, preferred stock, and common equity components of JDITC should correspond to the cost rates established for long-term debt, preferred stock, and common equity, and the cost rates for other components should be zero. Exhibit A-9, Schedule D1; Exhibit A-90; Exhibit S-4, Schedule D1.

6. Overall Rate of Return

Based on the foregoing, the Company's proposed Test Year Capital Structure which reflects the component balances agreed to by Staff, should be adopted. Further, the Cost Rates proposed by Staff, including its 10.00% ROE, should also be adopted.

[25] The Company notes that lower interest rates result in increased costs for its benefits obligations. That issue is addressed below.

Under that structure and Cost Rates, the Company's overall Rate of Return should be set at 5.90%. See Staff's Initial Brief, Appendix D.

The Capital Structure and Costs Rates recommended in this PFD are set forth in Appendix D.

VI. ADJUSTED NET OPERATING INCOME

Adjusted Net Operating Income (NOI) represents the difference between operating income and operating expenses during the test year. In this case, the Company projects its total jurisdictional revenues at $4.217 billion, and an after-expense net operating income of $499.628 million, which when the projected $5.663 million Allowance for Funds Used During Construction (AFUDC) adjustment is applied, results in a adjusted NOI of $505.291 million. See Initial Brief, Appendix C.

A. Jurisdictional Revenues and Sales Forecast

The Company projects jurisdiction electrical deliveries of 37,784 GWh during the test year, a 0.8% increase from 2014, based on a combination of econometric and end-use methodologies that factors in a number of variables, including weather, economic conditions, expected savings from smart energy and energy efficiency programs, and demographics. 7 TR 1279-1282. The projected deliveries include a line loss factor of 7.34%, which is consistent with the holding in Case No. U-17735. Id., 1283. See Exhibit A-10. Using the essentially same methodologies, the Company's peak demand forecast is expected to be "reduced by approximately 25 MW in 2016 and increasing to 196 MW by 2020 for the Company's load administration, peak pricing, prepaid meters, and web portal programs." 7 TR 1283. Mr. Breuring attributed the reduction to the Company's smart energy and energy efficiency programs. Id., 1284; Exhibit A-26.

The Attorney General, through Mr. Coppola's testimony, contends the Company's forecast testimony concerning its commercial and residential sales is unreliable based on the inclusion of sales decline of 125,155 MWh due to its Energy Optimization program, and 113,133 MWh from its Smart Energy program. 8 TR 2280-2281; Exhibit AG-1. Further, a 1% reduction, on top of the reductions based on the methodologies, projected for the test year as a result of these programs is not supported. See Exhibit AG-1. Mr. Coppola asserts the 1% reduction is derived from the goal of Public Act 295, not from any verifiable data. 8 TR 2281-2282. Along the same lines, any reductions based on web portal of the Paygo program are not supported, but merely aspirational. Since the forecast includes a loss of revenue from reduced sales that are unlikely to occur, Mr. Coppola recommends the test year savings attributed to smart energy/energy efficiency programs "be removed from the test year forecast for a total increase in forecasted sales of 238,288 MWh from the Company's forecast." Id., 2282. With that step, higher projected sales for residential and commercial customers would result in a $10,719,945 increase in revenue and operating income. Id., 2283; Exhibit AG-2.

The Company effectively rebutted the Attorney General's proposed adjustment of its forecast by noting the invalid assumptions underlying Mr. Coppola's analysis. First, Mr. Breuring testified the savings attributed to energy efficiency programs:

> [A]re removed from the regression analysis prior to executing the models to avoid skewing the coefficients in the manner Mr. Coppola claims. By removing the historical EE savings, the Company is able to forecast electric growth absent the EE savings it has observed since Public Act

> 295 of 2008 enacted the program. The historical and forecasted EE savings are then imported, along with the other exogenous adjustments, into the modeling framework to create the final electric deliveries forecast.
> 7 TR 1291.

Mr. Breuring also noted the 1% Mr. Coppola claims is derived from the Act 295 goal, as opposed to actual data, reflects the 1.3% reduction in residential and commercial deliveries set forth in the 2010-2014 Energy Efficiency reconciliation cases approved by the Commission. 7 TR 1290-1291. Based on this testimony, the Attorney General's proposed adjustment to the Jurisdictional Revenues and Sales Forecast should be rejected.

The other component of the Forecast is Total Electric Operating Revenues, which for the test year is projected at a total $4.231 billion from Base Tariff, PSCR, and Miscellaneous. Exhibit A-10, Schedule E-1. Subsequently, the amount was adjusted to $4.240 billion to add expenses and revenue from various job work activities that are not reported as electric operating revenues. Exhibit A-8, Schedule C-3. Further adjustments to account for Residential Income Assistance ("RIA") and Residential Senior Citizen ("RSC") customer count adjustments result in a test year jurisdictional total revenue of $4.217 billion after accounting for jobwork expense. See Company's Initial Brief, Appendix C, page 1, line 1, column (d).

Staff seeks an increase to test year revenues of $4.501 million to account for an adjustment to the projected number of customers it contends are eligible for the RIA and RCS programs. Mr. Pung testified to the basis of this adjustment for the RIA program:

> When Staff evaluated recent historical levels of customers enrolled in the RIA provision, it was observed that the average number of customers enrolled has been declining since 2013. The five year average number of customers enrolled in the RIA provision from 2011 to 2015 is approximately 54,352. Furthermore, the average number of customers

> enrolled in 2016 from January through May is 54,158. Therefore, Staff adjusted the Company's proposed RIA level of 70,031 down to 55,045 to better align with the historical and current levels.
> 8 TR 2657.

Mr. Pung also testified to the adjustment based on the RCS program:

> Like the RIA provision, Staff evaluated the recent historical levels of customers enrolled on the RSC provision. The five year average for the RSC provision is not as relevant due to the Company's auto enrollment of senior citizens in August of 2015, which dramatically spiked the participation rate. The highest the RSC provision participation has ever been is approximately 383,795. This level occurred in August of 2015 after the Company's auto enrollment of eligible senior citizens. Participation has been in consistent decline since that time with the most recent figures coming in at approximately 370,521 in May of 2016. The Company's proposed determinant of approximately 437,529 has never been reached and recent figures do not support it. Staff recommends the Commission approve a RSC provision billing determinant of approximately 370,600 customers in alignment with recent data post auto-enrollment.
> 8 TR 2657-2658.

The Company agrees with Mr. Pung's adjustment of the RCS participation level to 370,600 customers from its initial projection of 437,247 customers. However, it disputes the RIA adjustment because while the average customer count for the most recent 12-month period is 54,004, approximately 12,000 of its customers qualify for the credit. 7 TR 1292. If the projection is lowered, and those customers apply for the credit, it would not be available because the program would be underfunded. Ms. Brege testified a software error that caused the Company to not identify eligible customers has been rectified, and enrollment of those customers has begun. 4 TR 727-728. It is reasonable to assume this will result in 12,000 customers being added to the RIA program, rendering the adjusted test year participation level of 66,000 proper. 7 TR 1292. Based on the adjustments to the participation levels of both programs, the test year revenue impact is $3,135,174. Id., 1293.

B. Fuel, Purchased, and Interchange Expense

Mr. Ronk testified to the components of this expense, along with the methodology the Company utilized to calculate the test year projection of this expense at $2,168,037,000. 4 TR 339-340; Exhibit A-56, pg. 1. Staff accepted the calculation of this expense. Exhibit S-3, Schedule C-1. The Company's jurisdictional fuel cost is $2,146,990,000. See Exhibit A-26 (EMB-5); Appendix C, page 1, line 5. Staff's jurisdictional fuel cost is $2,144,591,000. See Exhibit S-3, Schedule C1. [26]

C. Other O&M Expense

1. O&M Expenses Categories

   a. Distribution and Energy Supply O&M (Non-AMI)

For the Electric Distribution Department O&M expenses equate to $239,942,000 in 2014, $219,636,000 in 2015, $226,925,000 in 2016, and $238,353,000 for the 12 months ending August 31, 2017. 6 TR 1105; Exhibit A-16. The projected test year expenses consist of $249,266,000 for the Electric Division, which includes a $14,585,000 reduction due to the Smart Energy Direct O&M benefits, and $3,672,000 for Customer Payment programs. Exhibit A-15. For the most part, O&M expenses are attributed to Electric Division programs: Electric Energy Operations and Services; Electric Energy Delivery; and Electric Customer Operation and Quality (excluding uncollectible write-offs). 6 TR 1117. The difference between the expense levels in the projected test year and the Company's 2014 actual total Electric Division Expense is due to: (1) a $16,300,000 reduction in service restoration, corrective maintenance, and

[26] The record does not provide any indication for why the Company and Staff arrived at different amounts for this expense. Given the Company provided a basis for the components of this expense through the testimony of Mr. Ronk, while Staff did not, the Company's amount will be utilized.

HVD lines demand expense which is related to a change that took place beginning in early 2015 to capitalize some pole-top hardware replacements; (2) an increase of $17,400,000 in Line Clearing expense; (3) an increase of $2,000,000 in Smart Energy Customer programs expense; (4) an increase of $6,200,000 in ongoing O&M costs associated with distribution and customer service-related technology improvements; and (5) an increase of $1,100,000 in North American Electric Reliability Corporation ("NERC") distribution compliance cost. 6 TR 1108. Mr. Bordine explained the reasons underlying the reductions and increases in these programs. See 6 TR 1109-1117. The Parties have challenged certain aspects of the Electric Distribution Department projected O&M expenses

i. Vegetation Management/Line Clearing

The Company projects $57,300,000 for its Vegetation Management, which includes $53,300,000 for line clearing for its Low Voltage Distribution (LVD) system, and $9,000,000 for its High Voltage Distribution (HVD) System. These costs are based on the recommendation of the Company's consultant, Environmental Consultants, Inc., (ECI), which after an:

> [E]xtensive assessment of the Company's LVD line-clearing program and workload projections. It concluded that the Company should utilize a seven-year average cycle for its LVD line-clearing program. It also recommended that the Company address dead or dying hazard trees that are up to 20 feet outside of the right-of-way. These conclusions were based on the evaluation of the following factors: (1) tree caused outage data trends by circuit; (2) the percentage of Consumers Energy's overhead primary system miles that operate at a 4.8/8.32 kV nominal voltage; (3) the common use of 50-foot poles in urban areas; and (4) the percentage of trees in the right-of-way contacting primary conductors.
> 6 TR 1109-1110

Based on that recommendation, the Company intends to:

> The test year amount supports clearing approximately 1,120 HVD miles and 8,000 primary LVD miles. This compares to 879 HVD miles and 3,397 primary LVD miles at the expense of $40,163,000 in 2014 and approximately 736 HVD miles and 3,633 primary LVD miles at the preliminary expense of $37,012,000 in 2015. The test year projected funding will result in line clearing of approximately 25% of the HVD system, and approximately 14% of the primary LVD system annually (or an effective clearing cycle of approximately seven years) and would include funding to address hazard trees, such as dead or dying ash trees that have been affected by the Emerald Ash Borer, that are up to 20 feet outside of the right-of-way.
> 6 TR 1110

Mr. Bordine testified the program will address the cause of approximately 25% of customer interruptions, which is expected to rise if increased line clearing efforts are not pursued. 6 TR 1111. Mr. Bordine also testified the 7-year effective clearing cycle the Company proposes is longer than the 4-6 year effective cycle industry standard, it is more effective and reduces the clearing cost per mile. Id., 112-1114.

Staff seeks a reduction in Vegetative Management spending from $57,300,000 to $48,500,000, the amount set in U-17735, because the Company has not spent the amounts approved in rates over the past 4 years. 8 TR 2583. Mr. Laruwe also testified to Staff's concern that while the Company's spending plan is based on a recommendation of its consultant that is based on a traditional cycle implementation, the Company is using an effective cycle. Id., 2584; Exhibit S-9.3. Mr. Laruwe contends the traditional cycle is the industry standard:

> [A]nd until the Company commits to deploying this best practice and spending Commission approved funding amounts, Staff is not supportive of any increased spending plan in this program. Given the historic spending patterns for Vegetation Management, Staff finds it highly unlikely that the approval of higher spending in this program will result in increased tree trimming expenditures. Furthermore, increasing spending on a program that deploys an effective cycle will provide minimal benefits

> compared to utilizing the actual cycle recommend by ECI [the Company's consultant] and Staff. Therefore, Staff is recommending the test year spending plan for Vegetation Management be held at its current level of $48,500,000.
> 8 TR, 2584.

The Attorney General seeks a reduction of line clearing expense based on the failure to spend to approved levels in the past, and the contention the Company's requested level is unnecessary. 8 TR 2288-2291. Mr. Coppola recommends the Commission approve the same level in this case as the $48.5 million approved in U-17735. Id., 2891.

On behalf of ABATE, Mr. Rackers contends the projected line clearing expense:

> [I]s a dramatic increase compared to its current level of spending. Line clearing expense of $57.3 million represents an increase of over 50% compared to the level of spending achieved in 2015. The Company's budget for line clearing in 2016 is $48.2 million, which is a level it has not been able to achieve in the last five years and is nearly 16% below the Company's $57.3 million test year request. Furthermore, the high level of 2016 budget expenses includes four months of Consumers' proposed test year. If Consumers was able to meet the level of expense it has budgeted for in 2016, that would reflect approximately $16 million during the last four months of 2016, the first four months of the test year ending August 2017. Consumers would then have to spend an additional $41 million during the first eight months of 2017, to reach its lofty test year proposal of $57.3 million. This would reflect a monthly increase in spending of over 28%. Given Consumers recent spending levels, this proposed drastic increase in test year spending appears extremely unlikely to be achieved.
> 8 TR 2055

Mr. Rackers also testified the Company's projected test year expense reflects 9,100 miles of line cleared, a 100% increase over actual miles in 2014 and 2015. Given the discrepancy between the approved spending and actual spending and miles of lines cleared, Mr. Rackers recommends the $57.3 million sough in this case be reduced to $45.2 million, which is:

> [T]he highest spending on line clearing achieved by Consumers in the last five years. It also nearly reflects the current level included in rates, which Consumers has not achieved since 2011. Line clearing expense of $45.2 million reflects a significant increase, over 20%, above the 2015 level of line clearing, but is far less than the over 50% increase that would be required to achieve the level proposed by Consumers.
> 8 TR 2058.

In the event the projected expense is approved, Mr. Rackers recommends the Commission require the Company:

> [P]erform line clearing for its system based on a seven-year cycle. As part of this requirement, the Company should also provide annual reporting on its progress toward meeting the seven-year cycle. This will ensure that the Company adheres to the plan recommended by its consultants as the appropriate operating cycle and continues to make progress in meeting this requirement. Second, the Commission should order a tracker and refund provision to ensure Consumers meets its annual spending requirements according to the seven-year cycle requirement. This will protect customers from overpaying for line clearing in rates, as has been the case in recent years.
> 8 TR 2058-2059.

The Company contends relying on historical spending is inappropriate. 6 TR 1165. Rather, the focus must be on the basis and benefits of its spending plan, which includes mitigating one-quarter of the cause of outages and reducing restoration times by clearing 14% of the LVD system and maintaining 25% clearing of the HVD system. Id., 1165-1166. Mr. Bordine also testified the effective cycle is best suited to improving reliability because it allows for adjustments to tree trimming schedules, as Staff advocated in Case No. U-17542. Id., 1167. Mr. Bordine also indicated the Company is willing and capable of spending the entire amount it projects for the Test Year, as evidenced by the $24,119,000 it spent in line clearing in the first 6 months of 2016.

While the Company objects to considering actual spending when determining the reasonableness of actual spending, the Commission did just that in U-17735, noting the "company has never spent more than $45 million annually on the line clearing program, and accordingly, is unlikely to spend the requested $57.7 million." Case No. U-17735, November 19, 2015 Order, pg. 58. The record in this case indicates that the Company continues to under-spend in this program, and as Mr. Rackers noted, is unlikely to approach the approved spending level in 2016 based current spending. 8 TR 2055; see also 8 TR 2291. The Company acknowledges it has not spent the approved amount, but contends it is due fluctuations in programs resulting from the need to manage and balance capital investments and O&M expenses. 6 TR 1177-1178. While that may be true, as a general principle, the Company has not provided any substantive basis to explain why, over the past 5 years, it has not approached spending at approved levels, let alone at the level projected for the test year. Accordingly, it is recommended that the amount proposed by ABATE for line clearing, $45.2 million, and for the reasons testified to by Mr. Rackers, particularly his determination that amount represents the highest spending level over the past 5-years be approved. See 8 TR 2054-2058.

ii Pole-Top Hardware

ABATE also recommends a $3.3 million reduction in the Company's revenue requirements for pole-top hardware replacement costs. This recommendation is based on Mr. Rackers' testimony regarding this component of the cost of service:

> The current rates reflect expensing of pole-top hardware replacements during 2015 and 2016 and will continue to do so until the rate change effective as a result of this case. Therefore, customers are currently paying for $16.3 million of annual pole-top replacements in current rates. Now that Consumers is capitalizing these costs, the 2015 and 2016 pole-top replacements will be included in the plant investment used to establish

> the rates resulting from this case in 2017. However, this plant investment has already been paid for in rates. Consumers will over-recover these investments, once as customers continue to pay the annual cost of pole-top replacements through current rates, and again as customers pay for the recovery of 2015 and 2016 pole-top hardware included in the rate base used to establish rates in the current case.
> 8 TR 2064.

However, Mr. Bordine testified the Company is not seeking any changes from the rates approved in U-17735, which account for the capitalization of pole-top hardware. 6 TR 1198-1199. Since the O&M for the program is reflected in the current rates, and the Company is not seeking any changes in this, the over-recovery Mr. Rackers determined will occur is incorrect. Therefore, the reduction for pole-top hardware sought by ABATE cannot be sustained.

iii. Customer Payment Program

Mr. Coppola also proposed the elimination of the $3.7 million projected cost of the Company's Customer Payment Programs because it may lead to reduced costs through lower uncollectable accounts. 8 TR 2292. The increased cost of this program is a result of the Company's elimination of a $6.25 fees it charges for credit card payments to avoid shut-offs, which Mr. Coppola believes may reduce uncollectable accounts. However, Mr. Bordine testified the Company does not ascribe to the theory that the $6.25 fee will in any manner reduce uncollectable accounts, nor does Mr. Coppola provide any support for this contention. As Mr. Bordine notes, eliminating this fee is consistent with the credit and debit card practices of most other businesses, including DTE, and is a benefit to the Company's "most vulnerable customers." 6 TR 1183. Based on this evidence, the Atorney General's proposed adjustment to the Customer Payment Program should be rejected.

iv. Filing Requirements

Staff also requests, relative to O&M and capital spending, future filings include "variance reports that provide transparency into the Portfolio Management Process and a thorough prudency review of its operation in the time period between the historic test year and projected test year." 8 TR 2586-2587. These reports would alleviate the current problem, as characterized by Mr. Laruwe, of the Company not providing any substantive basis for the variations, which then requires the other parties to obtain the information before it begins its prudency reviews. Mr. Laruwe provided specific examples the variations in pro-active and reactive distribution programs relative to preliminary spends and approved spends in U-17735. 8 TR 2586. Mr. Laruwe testified to the necessity of this step:

> Currently, the Company provides a historic cumulative total spend for Distribution O&M and short explanations of significant variations from the historic spend and new expense categories. The Company expects these expenses be deemed reasonable and appropriate based on a benchmarking study that compares the operating expense per utility customer across the United States and ranks the Company in the second quartile. Staff does not believe that this comparison provides any support of the reasonableness of the Company's expenses as each utility is unique in its operation given the numerous circumstances that drive operating costs making them nearly impossible to compare. The more appropriate way to review operating expenses is to look at historic spending on the Company's O&M programs and comparing them to projections. Looking at the costs associated with operating the Company's system year over year provides insight into where investments are occurring that a high level benchmarking cannot. Furthermore, intervenors have no familiarity with these other utilities included in the benchmarking and no ability to audit the numbers provided in the benchmarking study. Providing recent historic and projected test year program level expenses in Distribution O&M in the Company's application similar to what was provided in audit response #84 (Exhibit S9.6 (RSL-7)) will alleviate the substantial burden placed on intervenors to obtain this information to begin a prudency review. Given the timeframe of rate cases, the collection of this data should not be the burden of the intervenors as it should be readily available to the Company. 8 TR 2587-2688.

The Company objects to this requirement, noting the information requested by Staff in rate filings was provided in this case regarding certain programs. 6 TR 1169-1170. Any additional information should be, and in this case was, provided through discovery and audit requests, especially since over 50 programs are subject to change and providing that information on each one would be burdensome. Finally, the Company contends Mr. Laruwe's criticism of its benchmarking distribution capital and O&M is misplaced because it only does so when the data is from "reliable and unbiased sources." Id., 1173.

Staff's concerns over the information available to it, and the Intervenors, in rate cases is well-taken. This is especially true under the time-frames those parties operate under, which makes it difficult to identify, request, and ultimately obtain the information necessary for the sufficient review of a rate filing. The Company's contention that it would be burdened by the imposition of the filing requirement Staff seeks is belied by its contention that the information is provided through discovery. If the Company has to gather and disclose the information during that process, it can also do it when compiling its rate filing. Further, the Company is not being asked to provide every conceivable data point, but rather identify with a reasonable degree of specificity the reasons for the variations in these programs, which Mr. Bodine testified it did for certain programs. Therefore, it is recommended the Commission grant Staff's request that future filings include support for reasonableness of projected costs, including investments planned for the test year and an explanation why investments previously approved were not made, consistent with the report cited by Mr. Laruwe. 8 TR 2586. In addition, the Company should be required to provide greater insight into all individual distribution

O&M program expenses, including historic spending on O&M programs and projected test year spending and explanations of variations, similar to Exhibit S-9.6. Id., 2587-2588.

b. Fossil & Hydro Generation O&M Expense

In its Application, the Company projected a test year expense of $148,793,000. 7 TR 1582; Exhibit A-44. However, in response to the Commission's Order in Case No. U-17918, the projection was lowered to $146,993,000. Company's Initial Brief, Appendix C, pg. 3. Mr. Kehoe testified to the specifics of that projection, including Environmental Operations, Jackson Gas Plant expenses, and Major Maintenance expenses. 7 TR 1585-1593. Staff takes issue with 2 expenses under this category.

i. Jackson Plant Pipeline Demand Charge

The first expense is to recover the Company's pipeline demand charge for the Jackson Plant. The Company is also seeking recovery for this expense through a PSCR proceeding, which was approved by the Commission in its October 11, 2016, Order in Case No. U-17918. As a result, the Company agrees with Staff's request to remove $1.8 million for the demand charge from the Fossil & Hydro Generation O&M expenses.

ii. Environmental Operations

The next O&M expense Staff challenges is $16,308,000 the Company's projects for Environmental Operations during the test year to install Air Quality Control Systems (AQCS) at its power plants to comply with state and federal emission standards. 7 TR 1621; Exhibit A-44. Staff recommends removing $3,262,000, which is 20% of the projected expense. Mr. Evans provided the basis of that recommendation:

> The Company has overprojected with regards to environmental O&M in past rate cases. Overprojecting is defined in this instance as when the Company's projected O&M expenses are greater than the actual expenses. Overprojecting occurred in Case No. U-17087, when the Company projected expenses for "SCR Operation excluding Urea Costs" of $2,821,000 and "Pulse Jet Fabric Filter Operation" of $168,000, both for 2013. (Footnote/confidential omitted). Together, these add to $2,989,000. However, the Company only ended up spending $2,378,000, or 79.6% of the projected amount. (Footnote omitted). In Case No. U-17735, the Company projected Environmental Operations expenses of $5,026,000 for 2014. 16 The Company only ended up spending $3,958,000, or 78.8% of the projected amount. (Footnote omitted). Also in Case No. U-17735, the Company projected Environmental Operations expenses of $12,237,000 for 2015. (Footnote omitted). However, the Company ended up spending $6,249,000, or 51.1% of the projected amount, as shown in Exhibit S-8.6, column (d), line 3. Based on this historical trend of overprojecting, Staff believes it is appropriate to recommend applying a downward adjustment of 20% to the Company's Environmental Operations request in this rate proceeding. **The Commission should note that this downward adjustment is less than the magnitude of overprojecting that has occurred every year since 2013**. (Emphasis in original).
> 8 TR 2568

In response, the Company does not deny that it over-projected Environmental Operations expenses in 2013, 2014 and 2015, but contends it was unavoidable and unlikely to occur again. 7 TR 1622. In regards to the latter, Mr. Kehoe testified the units with AQCS did not operate as planned, construction projects took longer than expected, and dates for compliance with state emission standards were extended. Id., 1622-1625. However, since the Company has completed the AQCS projects, and the units are operating in accordance with emission standards, the Company reasonably expects to spend the projected $16,308,000. Id., 1626.

The Company makes a good point that Staff did not contend the expenses in 2013-2015 were unreasonable at the time they were projected, but rather is using hindsight to claim that because the expenses were over-stated in the past, they are likely over-stated in this case. However, Mr. Kehoe's testimony that the causes of the over-projections are resolved, i.e. AQCS is installed at the units and as of April 2016 operating to achieve compliance with emission standards, gives credence to the Company's argument that the expenses in this case are not over-stated. Further, Staff does not contend the generating unit availability, upon which the test year projected expenses are premised, is deficient. See Exhibit A-43. Accordingly, the Company has established its projected Environmental Operations O&M expenses are reasonable, and Staff's challenge to those expenses should be rejected.

Based on the foregoing, the Fossil & Hydro Generation O&M expenses should be adjusted $1.8 million to remove the Jackson Plant pipeline demand charge.

c. Corporate Service O&M Expense

These expenses include Human Resources and Administrative Services, Internal Control and Compliance, Legal, Corporate Risk Management, Corporate Secretary, Governmental/Public Affairs and Corporate Compliance, Controller's Area, Rates and Regulation/Regulatory Affairs, Strategy and Research, Strategic Innovation, Corporate Tax, Financial Planning and Treasury, General Activities costs, and Administrative and Other costs. 7 TR 1539-1542. For the test year, the O&M expenses are projected at $53,480,000, which is derived from 2014 actual, 2015 preliminary, and projected amounts for 2016 and the 12 months ended August 31, 2017, along with certain adjustments. Id., 1542-1545; Exhibits A-37 and A-38. None of the parties recommended any adjustments to this expense, except for $3.0 million O&M expenditure for economic development.

The economic development expenditure are for what Mr. Mayes termed:

> [C]osts associated with efforts to promote load growth, job creation, and new business investment that will benefit our electric customers. This

> funding would support increased staffing, marketing, and other economic development activities that are fundamental to business attraction and expansion. Additional activities would be performed in cooperation with other organizations engaged in economic development.
> 5 TR 773.

Mr. Mayes also testified to the numerous benefits the Company ascribes to engaging in economic development activities, which includes load growth and job creation. 5 TR 772-773. The Company's economic development is performed in conjunction with local and state entities, and is consistent with the industry trend of utilities engaging in this activity. Id., 774. As for the recent benefits of this activity, the Company points to three new customers it has brought into its service area that increased its sales by 288,000 MW/h a year and resulted in a $12 million recovery in fixed costs. Id., 777-782. In 2015 the Company had 25 new and existing customers use 74 MW of load that Mr. Mayes attributed to the Company's economic development efforts. Id., 783. However, it was a potential customer it lost, a foreign glass manufacturer looking to construct a $250 million plant that contributed to the Company's decision "to enhance our economic development competitiveness, continue efforts to lower industrial rates, and improve the way we responded to customer investment opportunities." Id., 776-777. The $3 million expenses for economic development translates to 9¢ a month increase, on average, in the rates of residential ratepayers, which Mr. Mayes testified results in a benefit of new load that reduces fixed costs. Id., 782.

Staff does not support the Company's request because despite its claims to the contrary, no performance metrics are proposed that would "measure the success of the program and to hold the Company accountable for spending." 8 TR 2527. Staff also notes the State of Michigan spending on economic development that includes attracting national and international businesses to the State. Id., Exhibits S-11.2 & S-11.4. Staff expressed concern that other utilities that don't engage in economic activities will be disadvantaged by the Company's expansion in this field. Finally, Staff contends economic development is "not a core utility function that is required to provide safe and reliable service at just and reasonable rates." Id., 2527-2528.

The Attorney General also opposes including the cost for economic development in rates. Mr. Coppola notes that of the $3 million the Company seeks in this regard:

> Approximately $1.8 million would go to double the current economic development staff from 3 employees to 6. This would imply compensation and perhaps related expenses of approximately $300,000 per employee. An additional $600,000 would go to likely hire consultants to perform professional research and program development. The remaining $600,000 would be spent on marketing programs and business attraction/relationship building expenses (most likely travel and entertaining expenses, etc.).
> 8 TR 2295, referencing discovery response to AG-CE-315.

Mr. Coppola also testified, similar to Mr. Nichols, economic development does not fit with the Company's "basic core function of providing utility services." 8 TR 2297. While he does ascribe to the benefits of increased customer and sales growth, achieving it through economic development activities, which is adequately performed by state and local governmental entities, is beyond the Company's core function. Id. Mr. Coppola also criticized the Company's failure to establish goals/targets that would quantify the success of the program relative to the funding increase.

Mr. Zakem, on behalf of Energy Michigan, identified only one potential benefit to the Company's utility business resulting from economic development: load growth. However, whether that load growth is, standing alone, a benefit to customers is debatable because it may require additional resources, such as generation, distribution, and transmission that may have incremental costs greater than current average costs, which will cause rates to increase. 8 TR 2741. Mr. Zakem also determined the economic development costs will adversely affect Full Service and ROA customers, and if the Commission approves the request it should also allocate power supply and distribution separately on the basis of relative dollar investment, and collect accordingly from those rate classes. Id., 2743-2744. Mr. Zakem recommends the Commission deny the request, and if the Company deems it a “wise investment”, fund the activity through its shareholders.

On behalf of ABATE, Mr. Gorman took issue with Mr. Zakem’s proposed allocation for economic development costs because the costs are not related to energy consumption or vary with the consumption by a rate class. 8 TR 2135. Rather, Mr. Gorman found the Company’s proposed allocation, an administrative and general expense “allocated to customers using a mix of labor-related allocation factors and functional allocation factors tied to general O&M expenses” reasonable. Id., 2136.

Mr. Sansoucy also took issue with the Company’s proposal, noting that contrary to Mr. Mayes’ characterization, the impact to residential customers would not be minor if the proposed production costs allocator that would increase residential customer’s costs $31 million annually that Mr. Mayes supports is approved. 8 TR 2180. Rather than the 9¢ average monthly increase for residential customers Mr. Mayes testified to, the economic development expense “equates to an average of another $19.62 per year per customer. Added to the $1.08 per year for economic development expense, this totals over $20 more per year that Consumers wants residential customers to pay in order to facilitate the company's effort to attract more industrial customers to its service territory. This "strategy" – if one could call it that – is unreasonable and inequitable." Id., 2179.

As was the case with the proposed PEV charging station program, the Company's economic development activities are well-intentioned, and assumedly has, to some extent, played a role in bringing business to the state. However, the points raised by both Staff and the Attorney General are accurate. First, economic development does not align with the core function of a regulated utility: providing safe and reliable service at just and reasonable rates. If the Company wishes to pursue economic development activities beyond, or in conjunction with, state and local government, it may do so with shareholder, as opposed to ratepayer, funds. Assuming economic development activities are considered with the core function of a utility, the record is devoid of any substantive evidence that would allow the measurement of the benefit to ratepayers that would result from the expenditure of $3 million for that purpose. For example, the Company points to the new businesses that have moved into its service area and the increased load that followed. However, no indication was given on how that can be attributed solely to the Company's economic development activities, and not the myriad of other factors that play a role in siting a project. Along the same lines, no indication was given on how exactly the $3 million in ratepayer funds would have made a difference in the project that did not move into the Company's service area. 8 TR 2296-2297. Accordingly, the Company's proposal to include $3 million in O&M for economic development should be rejected.

d. IT Expenses

The test year projection for the IT Department O&M is $43,326,000. 7 TR 1376; Exhibit A-60. Mr. Varvatos testified the methodology utilized to arrive at the projection, along with cost control measures the Company utilizes for IT, including contracting certain services, and its project prioritization process. 7 TR 1379-1380. None of the parties recommended any adjustments to this expense.

e. Pension and Benefits

In its Application, the Company projected an O&M expense for employee benefits at $54,695,000. Exhibit A-48. This amount consisted of: (1) a Pension Plan expense of $21.244 million; (2) a Defined Benefit ("DB") Supplemental Executive Retirement Plan ("SERP") expense of $2.422 million; (3) a Defined Company Contribution Plan ("DCCP") expense of $7.469 million; (4) a Defined Contribution ("DC") SERP expense of $239,000; (5) a 401(k) savings plan expense of $7.674 million; (6) an active employee health care, life insurance, and long-term disability insurance ("LTD") expense of $28.012 million; and (7) a retiree health care and life insurance expense of ($12.365 million). Id. The Company presented extensive evidence concerning the methodology used to arrive at the projected expenses for the 7 categories. See 5 TR 484-485, 8 TR 1782-1829; Exhibits A-48

Subsequently, and in response to Staff's proposed reduction in the long-term debt cost rate that this PFD recommends the Commission adopt, *supra*, the Company projects a corresponding $14 million increase in its Pension and Benefits expenses. 5 TR 483-485. Staff argues the Company's increase is unreliable and should be rejected. In support, it notes the increase is due only to a change in one of the many assumptions underlying the calculation used to ascertain liabilities for pension and OPEB. See Exhibit S-14, pg. 67. To fully ascertain what, if any, increase should be attributed to this change a full actuarial remeasurement is necessary, which the Company has done in numerous other proceedings and is required under GAAP. See Staff's Initial Brief, pgs. 112-116. This contention is accurate, and thus the record is devoid of any substantive evidence that would establish the adjusted long-term debt cost rate will result in a corresponding increase in Pensions and Benefits. Therefore, the $14 million projected increase to Pension and Benefits O&M expenses should be rejected, and the amount set at $21.244 million, which is what the Company initially projected. See Exhibit A-8. With the exception to the adjustments proposed by Staff and the Attorney General, which are addressed below, the other components of the Company's projected Pension and Benefits O&M expenditures should be adopted. Exhibit A-8, Lines 8, 9 &11.

i. Active Health Care/Life Insurance/LTD

Staff seeks a reduction of $3,348,000 in the active health care component of this expense, which would set it at the level of actual 2015 costs. 8 TR 2536; Exhibit S-3, Schedule C5. Mr. Nichols testified to three reasons for this adjustment. First, since 2011, when active health care cost $28.6 million, to 2015, when the cost was $24.7 million, the costs have gone down approximately $1 million a year. 8 TR 2536; Exhibit S-11.10. Second, the Company has told investors that through attrition, which is apparently a reference to an annual net loss of 100 employees, O&M costs were reduced by $35 million in 2014-2015, with another $35 million in reductions anticipated in 2016-2017. Exhibit S-11.14. In addition to the net reduction in the number of employees, reduced costs are attributed to the departing employees receiving defined benefits, while the new employees receive defined contribution. The Company conceded that attrition "may play a part…" in the 5-year trend of $1 million per year reduction in active healthcare. Exhibit S-11.15. Third, in U-17735 the Company projected active healthcare/life insurance/LTD at $26.9 million for 2015 and $27.5 million for the projected test year ending May 31, 2016, both of which are "significantly higher" than the actual amount $24.7 million for 2015. 8 TR 2537. Accordingly, the Staff recommends this O&M expense be set at the 2015 actual amount, $24,664,000. Id.

The Attorney General's proposes a reduction of $2.6 million for active health care, which would set it at the 2014 level. This reduction is also based on the fact the costs have declined over the past 5 years. 8 TR 2315; Exhibit AG-5. Mr. Coppola also noted the Company has implemented cost savings measures in 2016 such as higher co-pays and deductibles, and using the 2014 level, as opposed to the lower 2015 amount proposed by Staff, protects against any unexpected cost increases. Id., 2316. Mr. Coppola also testified the Company's projection includes a 5% increase in this expense in 2016 and 2017, but offers no justification.

The Company utilized a number of factors in its active health insurance cost projection, including health care cost trends on a national level and its insurers expectations based on claims, age of its employees and retirees, union contracts, and current number of employees. 8 TR 1809. Another factor were health care cost surveys that forecast 2016 increases between 4% and 8%, and estimates from its consultants that the Company's costs could increase between 5% and 9%.

Id., 1809-1890. Further, the Company's efforts to reduce costs in the previous years will eventually stop resulting in savings. Id., 1835. In effect, the Company contends that it has realized all the health care cost savings that are reasonably attainable, and from that point its costs will increase, which is why it included the 5% increase the test year projection.

Obviously, the 5-year annual average decrease of $1 million that Mr. Nichols testified to is an indication the Company has taken positive steps to reduce its active health care costs. While Mr. Kops testimony that the savings from those steps will produce diminished returns in the future is valid, it is difficult to accept the proposition those savings will end and the Company's costs will increase by the magnitude suggested by the test year projection. Further, as Mr. Coppola testified, those measures continued to be implemented in 2016, meaning savings will continue to be realized. Along with the cost savings measures, a reasonable presumption is the Company's costs have gone down because of attrition, a fact the Company does not refute. Exhibits S-11.14 & S-11.15. [27] Accordingly, the Company's projected test year Active Health Care/Life Insurance/LTD costs of $28.012 million, which is premised on a 5% increase in health care costs in both 2016 and 2017, cannot be sustained. While Staff's projection, the Company's actual 2015 health care cost of $24.7 million, is sound, Mr. Coppola's recommendation of using the higher 2014 actual expenses in the event the annual reductions do not continue at the current level is reasonable. Therefore, it is recommended the Active Health Care/Life Insurance/LTD O&M test year projection be set at $25.4 million, which is a $2.6 million adjustment.

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[27] The testimony of Mr. Varvatos that IT O&M costs are reduced, in part, due to contracting certain services in that area goes to the proposition that attrition is the primary driver of the 5-year health care costs reductions. 7 TR 1379.

ii. Benefit Plans

Staff and the Attorney General seek the removal of all expenses, totaling $2.6 million, associated with two supplemental retirement plans: the Defined Benefit Supplemental Retirement Plan (DB SERP), and the Defined Contribution Supplemental Retirement Plan (DC SERP). Mr. Nichols, along with Mr. Coppola, noted the Commission, along with regulatory commissions throughout the country, have disallowed recovery in rates of the costs of non-qualified benefit plans for executives. 8 TR 2314, 2535-2536. The reason for the disallowance is the expense does not provide any benefit to ratepayers. Id., 2535. Mr. Coppola also noted that the Company has failed establish these plans provide any benefit to ratepayers, other than the contention they are necessary to attract and retain executive management. Id., 2315.

Mr. Kops testified to the general principles of both plans, along with how the projected test year expense was calculated. See 8TR 1792-1800; Exhibit A-48. In response to the arguments of Staff and the Attorney General, the Company counters that both DB SERP and DC SERP provide benefit to ratepayers by allowing it to attract, retain, and motivate executives, who, in turn, make decisions regarding safety, system reliability, improved productivity, and a financially healthy that provides direct benefits to its customers. 4 TR 1794, 1801-1802. In addition, these executives make decisions that result in lower costs, such as those underlying the reduction in health care and pension plan costs, which benefit ratepayers. However, making prudent decisions that benefit ratepayers, such as making effective cost reductions, does not translate to the $2,422,000 cost of DB SERP and the $239,000 cost DC SERP for the test year translating to a commensurate benefit to ratepayers. As was the case in U-17735, this record does not provide a basis to find the $2.6 million cost of the two supplemental retirement plans is reasonable and prudent, and the adjustment proposed by Staff and the Attorney General should be adopted.

f. Employee Incentive Compensation Plan

The Company seeks to recover test year costs of its Employee Incentive Compensation Plan (EICP), which is designed to reward performance over a period of 1-year or less (short-term plan). 6 TR 1002. In addition, recovery is also sought for the test year expenses of a plan that rewards performance and tenure over a period longer than 1 year (long-term), through the issuance of restricted stock with a 3-year cycle. Id., 1002, 1028-1029. Ms. Conrad provided a general over-view of the Company's compensation for both groups of employees, along with the general parameters of the EICP. 6 TR 1005-1018; Exhibit A-33. In 2015, the EICP had 15 specific performance metrics for non-officer employees, covering safety, reliability, customer value, and financial, which Ms. Conrad indicated will also be used in 2016. Id., 1019; Exhibit A-30. However, payout levels will change in 2016, and assumedly that structure will extend into 2017. Id., 1024. The goals for Officers of the Company are essentially the same, although weighted differently. Id., 1025-1028. For the test year:

> The Company is requesting recovery of electric expenses related to incentive compensation plans at target (100.0 percent) levels. The level of expense is $14.4 million as illustrated in Exhibit A-32 (AMC-3). This includes $5.5 million for EICP incentive compensation and $8.9 million for long-term incentive (restricted stock) compensation. Incentive compensation for the proxy officers is not included in these amounts.
> 6 TR 1028.

Ms. Conrad testified the EICP awards should not be considered an addition to employee compensation, but a part of "the overall reasonable level of compensation."

Id., 1030. Ms. Conrad also testified at great lengths to the benefits that ratepayers realize from the EICP and long-term incentive compensation. Id., 1031-1038. Mr. Stuart made a quantitative analysis of those benefits, but at the same time acknowledged the difficulty in such an analysis for every program metric. Id., 963-967.

Based on the foregoing, the Company initially projected its incentive compensation plan costs at $14.377 million, but reduced that amount to $12.0 million, consisting of $3.1 million in short-term incentive, and $8.9 million in long-term incentive. 6 TR 1045; Exhibit A-89. Ms. Conrad provided the reason for the reduction:

> In the first quarter of 2016, subsequent to the filing of this Case No. U-17990, the Company began classifying annual incentive expense for the approved employee groups as a labor cost. This was a result of electric Case No. U-17735 in which the Commission issued an Order approving the recovery of annual incentive (Employee Incentive Compensation Plan ("EICP")) in rates for non-officers and non-proxy officers. The labor costs charge between O&M and capital is based on labor studies performed by each business unit. The data in Exhibit A-89 (AMC–5) has been revised to take this classification revision into account. Exhibit A-89 (AMC-5) should replace my originally-filed Exhibit A-32 (AMC-3).
> 6 TR 1045.

Staff seeks the exclusion of the entire cost of the Company's incentive compensation plan on 2 grounds. Exhibit S-3, Schedule 5; see also Initial Brief, Appendix C. First, the Commission has long held that incentive plans that are tied to financial metrics, such as earnings, benefit shareholders, and to shift the costs to ratepayers the Company must establish a tie to non-financial metrics and demonstrate a benefit to ratepayers. 8 TR 2530. In this case, both the short-term and long-term plans are to financial metrics:

> Achievements of target levels of performance in financial measures drive most of the plans' payout. For the officer plan, the safety, reliability, and customer value goals are a plus or minus modifier to the financial goals, [as testified to by Ms. Conrad, 6 TR 1004]. If no financial measures are

> achieved in either the officer or non-officer plans, payout for both the short and long-term plans would only be $2,124,103, or 15% of the projected expense (Exhibit S-11.9). This payout assumes target performance in all non-financial measures.
> 8 TR 2530-2531.

The Company's filings with the SEC confirm the plans are aligned with financial measures:

> Regarding executive compensation, page 29 of CMS Energy's 2016 proxy statement filed with the Securities and Exchange Commission states that "[t]he performance goals are set to provide consistent earnings growth and cash flow..." and page 24 states "We pay an annual incentive only if the Corporation's EPS and OCF [operating cash flow] meet or exceed the threshold levels set in January of each year."
> 8 TR 2531

The second basis for Staff's exclusion of the incentive plans costs is the contention neither are reasonable. On this point, Staff acknowledges that in the Company's last rate case, the Commission approved the inclusion of short-term incentive compensation in rates because the Company established a benefit accrues to ratepayers from those costs. U-17735, November 19, 2015 Order, pg. 77-78. [28] However, the Commission also held that that going forward, the Company must provide "additional well-defined evidentiary support demonstrating that the company's total compensation (historical and test year) are, in fact, reasonable compared to peer organizations." Id., pg. 72. In response to that directive, Ms. Conrad testified total compensation is targeted at approximately the market median of the Company's peers. However, Mr. Nichols contends that claim is suspect because the Company could not calculate "the amount of total compensation included in the projected test year" or even "to provide the amount of payroll included in the projected test year, therefore no

[28] The Commission maintained the long-time exclusion of long-term incentive compensation costs from rates because the benefits flow to shareholders. U-17735, November 19, 2015 Order, pg. 78.

comparison of historic payroll to projected payroll is available". 8 TR 2532-2533; see also Exhibits S-11.11, S-11.12, S-11.13, and S-11-17. Further, Staff takes issue with the Company's claim that the only the overall level of compensation must be reasonable, not the precise structure of the compensation programs. See 6 TR 1041. To Mr. Nichols, both factors are important, and the lack of information precludes a determination of whether the total compensation is at market median, and the cost results in a benefit to ratepayers, and thus should be excluded. 8 TR 2534.

The Attorney General also recommends excluding the entire costs of EICP. Exhibit AG-5. In this regard, Mr. Coppola relied on the same basis as Staff: the metrics are based on financial considerations that benefit shareholders, but not ratepayers. 8 TR 2301-2306. Mr. Coppola also found the purported ratepayer benefits claimed by the Company "highly inflated and often unsupported." Id., 2307. For example:

> Other cost savings related to productivity of $150 million and quality improvements of $1.9 million are mostly based on internal and subjective measures which cannot be objectively validated and relied upon. In this regard, the Company claims its O&M costs are lower by $150 million annually than they would otherwise be if O&M in 2006 were simply escalated by the CPI. These are not real savings in a period of low inflation but "what if" projections. The Company also claims its productivity has improved by 62% over the last ten years. With regard to this later point, which I regard as doubtful, the Company based this claim on weighted department-level productivity metrics for which it provided no support. No reductions in employee levels or capital requirements have been presented to justify a real improvement in productivity.
> 8 TR 2308-2309.

As noted, the Commission approved the Company's short-term incentive compensation plan in U-17735 because a benefit to ratepayers was established through 5 metrics: employee safety, distribution reliability, generation reliability, first time quality improvement, and productivity improvement. U-17735, November 19, 2015 Order, pg. 78. In this case, the Company set goals in 4 areas of operation: safety; reliability; customer value; and financial initiative. 6 TR 1019. Within those areas are 11 operational measures, which includes 4 of the 5 cited by the Commission in U-17735. Exhibit A-31. The Company provided, through the testimony of Mr. Stuart, the direct customer benefits it assigns to 5 of the metrics. [29] Utilizing a 63% allocation for electric customers for the savings under safety, quality, and productivity, results in a benefit of $98.080 million. When the benefits for distribution and generation reliability, all of which are realized by the Company's electric customers, are added, Mr. Stuart determined $134.512 million of total annual quantified ratepayer benefit tied to its incentive compensation program. 6 TR 965-966.

The premise of Mr. Stuart's analysis is the savings in the 5 areas he identified are attributable only to the short-term incentive compensation plan. In other words, the $3.510 million in savings from employee safety, i.e. the reduction in lost work days and medical expenses, were realized solely because of the incentive plan. Obviously, a number of factors would play into the decrease in costs the Company claims it has experienced as a result of employee safety. However, Mr. Stuart did not indicate any other factor, besides short-term incentive compensation, contributed to those savings. Along the same lines, Mr. Stuart attributes the $2.332 million annual savings in fuel expenses resulting from the reduction in the Company's annual forced outage rate, which dropped from 9% in 2006 to 1.5% in 2015, to the incentive plan's inclusion of a generation reliability metric. Id., 963-964. The premise that the short-term incentive plan, standing alone, resulted in $134.512 million in annual savings to ratepayers

[29] The 5 metrics that Mr. Stuart examined are employee safety, quality, productivity, distribution reliability and generation reliability. 6 TR 965.

cannot be accepted. While some benefit to ratepayers assumedly resulted from savings attributable to the metrics used in the short-term incentive, the quantification of an amount is not possible on this record.

In recognition of the difficulty in quantifying the benefit to ratepayers that can be directly attributable to incentive compensation, the Company seeks to have the Commission adopt the test used by the Indiana Regulatory Commission:

> In an April 27, 2011 Order in IURC Case No. 43839, the IURC stated at page 50:
>
> "The Commission recognizes the value of incentive compensation plans as part of an overall compensation package to attract and retain qualified personnel. The criteria for the recovery of incentive compensation plan costs is [sic] well established. We will allow recovery in rates when: (1) the incentive compensation plan is not a pure profit-sharing plan, but rather incorporates operational as well as financial performance goals; (2) the incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) shareholders are allocated part of the cost of the incentive compensation programs." Citing *N Ind Pub Serv Comm, 2010 Ind PUC LEXIS 294, at * 195-96.*
>
> The IURC recognized the value of incentive compensation plans as part of an overall compensation package to attract and retain qualified employees. Instead of requiring a quantification of customer benefits specifically related to the metrics of the incentive plan, which can be extremely difficult for measures that support undeniably desirable achievements (e.g., improved customer satisfaction and safety) the Indiana criteria require there be a combination of operating and financial metrics and a demonstration that there is no resultant excess compensation. This is a reasonable approach. [30]
> Initial Brief, pgs. 153-154.

The Attorney General provides a cogent point on the inherent flaw in the Indiana test. Meeting the first prong is accomplished by including an operational goals in the plan,

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[30] Ms. Conrad testified the 3rd prong of the IURC test, shareholder allocation, should not be adopted if overall compensation levels are reasonable. 6 TR 1033, 1035. However, in this case, shareholders are proposed to bear "a portion of these costs…." Id., 1033.

such as employee safety or generation reliability. In effect, the utility would be relieved from having to show the goal has been achieved, how the goal benefits ratepayers, and most importantly, whether the ratepayers have derived any benefit from the goal. Initial Brief, pg. 48. These are precisely the considerations that underlie the Commission's holding in U-14347, and its progeny, that incentive plans "require a showing that the benefits to ratepayers from the bonus and incentive plans, at a minimum, will be commensurate with the programs costs. Moreover, the utility has the burden of establishing how the proposed programs benefit ratepayers." Case No. U-14347, December 22, 2005 Order, pg. 34. Because the Indiana test would mark a dramatic shift from well-settled law in Michigan, it is recommended the Commission deny the Company's request to adopt it in this case.

This leaves the ultimate question of whether the Company has established its incentive plans provide a benefit to ratepayers commensurate with the costs they will bear for those plans. In regards to the long-term plan, it is premised solely on financial benchmarks: relative total shareholder return and relative earnings per share growth. 6 TR 1004. As such, they do not provide any benefit to ratepayers, and the $8.9 million in long-term incentive costs should be disallowed.

As for the short-term incentive plan, the benefits ratepayers Mr. Stuart contends will receive is not supported by this record. Further, Staff's contentions regarding the short-term plan, it is effectively driven by performance relative to financial metrics and the lack of information precludes a determination of whether the cost is both reasonable and results in a benefit to ratepayers, are valid. See 8 TR 2532-2534; see also Exhibits

S-11.11, S-11.12, S-11.13, and S-11-17. Accordingly, the $3.1 million in short-term incentive costs should be disallowed.

Based on the foregoing, all incentive costs, including O&M and capital, should be disallowed. [31]

g. AMI

For the test year, the Company projects O&M direct and common costs associated with the installation of AMI meters and associated activities of $13.762 million. 7 TR 1416; Exhibit A-6. The installation of the meters is expected to be completed in the Company's service area in 2017. 7 TR 1418-1419. Mr. Warriner an over-view, along with the status, of Company's development of AMI software and integration, which is critical to the functionality of the meters, expected to be completed in 2016. Id., 1420-1423.

Staff is proposing a $2.915 million disallowance for AMI O&M expenses, which would set recovery at $10.847 million. 8 TR 2611; Exhibit S-10.2. The adjustment is based on the fact the Company's actual expenses was 79% of the amount projected in previous cases. Id., 2611. The amount Staff recommends for this expense "was calculated using a 3-year average of the Company's projected versus actual O&M expenditures for 2013 through 2015, and applying the ratio to the projection in the current case." Id. However, Mr. Warriner testified the Company's projection was adjusted to reflect its actual experiences over the past few years, and Staff's reduction is duplicative of that cost reduction. 7 TR 1454. That step is reflected when comparing the projections in U-17735, $14.259 million in 2016 and $17.814 million in 2017, the

[31] While this case was pending, the Company moved $2.357 million for incentive compensation from O&M to capital. See Initial Brief, Appendix B, Line 5, Column b.; see also 6 TR 1045. The Company did not indicate this incentive was long-term or short-term, only that it applied to non-officers and non-proxy officers.

projections in this case: $11.956 million in 2016, and $14.661 million in 2017. Id., 1753. Based on Mr. Warriner's testimony, the Company's projected AMI O&M expenses are reasonable and should be adopted.

h. PEV Charging Station

The Company projects $150,000 in O&M expenses in the test year for this program. 6 TR 859; Exhibit A-50. Consistent with the analysis and recommendation concerning public and private charging stations, *supra*, this expense should not be accepted.

i. DR Expenses

The Company projects O&M expenses associated with its DR program at $2,815,000. 6 TR 859; Exhibit A-50. Consistent with the analysis and recommendation concerning the DR program, *supra*, this expense should be approved.

j. Uncollectable Expense

The Company projects this expense at $26.9 million for the test year. Exhibit A-40. Mr. Harry testified that amount "is based on a three-year average Bad Debt Loss Ratio ("BDLR") of net uncollectible accounts' expense to electric service revenue for the years 2013 through 2015…. This ratio is applied to the test year electric service revenue plus surcharge revenue…." 7 TR 1547. Mr. Harry testified this approach is used because the nature of the expense, which is primarily driven by the economy, with fuel and purchased power costs also a factor, creates "some likelihood that the future period's activity will be similar to the average of the past periods." Id.

Staff seeks a $1.826 million adjustment to this expense, which would set it at $25.094 million, based on as 5-year historical average, cash basis. Exhibit S-3, Schedule C5. Mr. Nichols testified to why this methodology is preferable to the Company's three-year approach:

> [U]ncollectibles expense can be sporadic and volatile over any given period of time and a five-year average can better smooth out any unusual variances that may occur. Additionally, a cash basis computation of uncollectibles is more appropriate than an accrual basis computation because it is based on actual write-offs less collections, therefore eliminating the volatility that sporadic uncollectibles reserve adjustments can produce in an accrual basis computation.
> 8 TR 2539

Mr. Nichols also noted the Commission approved this approach in U-17335.

Mr. Coppola criticizes the Company's methodology as "too simplistic and results in an inaccurate forecast." Id., 2299. Because this expense can vary from year-to-year due to weather conditions, economic conditions and many other factors, a more accurate approach is to use 5 years, which captures the highs and lows of costs and reflects the improving economy, in calculating the projection. Id.; Exhibit AG-5, pg. 3. Mr. Coppola set this expense at $30.1 million, excluding AMI benefits, by using "an average ratio of net charge-offs to revenue of 0.71% for the five years from 2011 to 2015 and the forecasted revenue of $4.225 billion for the future test year." 8 TR 2299. Using the Company's projected reductions in uncollectible expenses attributable to its AMI program, Mr. Coppola estimated a $5.4 million savings, reduces the expense to $24.7 million for the test year. Id., 2300.

The Company contends the three-year historical average is appropriate given that uncollectable expenses have gone up since 2011. 7 TR 1560. The Company argues this trend is diluted under Staff's approach, as evidenced by the fact its $25.094 million projection is at a level commensurate with 2011 when write-offs were $24.5 million. Id. Similarly, the Company argues Mr. Coppola's methodology dilutes the upward trend of uncollectible expenses. It is unclear how the Company can argue the 5-year average approach misses the trend of this expense given the variations starting in 2011, when Mr. Harry testified it was $24.5 million, to 2013, when it was $32.6 million, and 2015, when it was $27.48 million (preliminary). 7 TR 1560; Exhibit A-40.

As noted by the Commission, averaging the expense over a 5-year period is preferable to a 3-year period because it avoids an aberration in a particular year that can skew the results. U-17735, November 19, 2015, Order, pgs. 80-81. The Commission also found Mr. Coppola's ratio of uncollectable accounts write-offs to revenues over that period is the best method to project uncollectible expenses. Id., 81. Under that methodology, uncollectible expenses are $30.1 million. The Company did not dispute the $5.4 million is savings in uncollectible expenses Mr. Coppola attributed to the AMI program. In fact, the Company claims one of the benefits of its AMI program is "a reduction in uncollectible expenses." 7 TR 1434. Therefore, Mr. Coppola's recommendation of reducing the Company's uncollectable expense to $24.7 million for the test year should be adopted.

2. Electric Injuries and Damages

This expense, which the Company projects at $4.5 million for the test year, covers liabilities that arise in the normal course of business, and workers' compensation costs. 7 TR 1548-1549; Exhibit A-41. Mr. Harry testified the projection was arrived at by using a 5-year average of actual expenses for the three component costs: electric injuries and damages; internal legal costs; and workers' compensation costs. 7 TR 1549. No party sought an adjustment to this projection, and it should be adopted.

3. Meter Reading

Consistent with a Commission directive, the Company adjusted this expense downward $456,000 while this case was pending. See U-18002, June 9, 2016 Order, pg. 23; Exhibit A-70. This adjustment is characterized as the "costs that the Company estimates it incurred in the past associated with additional resources within the Customer Operations & Quality Department to handle customer calls, customer complaints, and billing issues and good faith credits issued to customers for issues from its past meter estimation practices." 6 TR 1148. Mr. Harry testified the treatment of good faith credits, as it pertains to rates, results in a $101,498 increase to test year revenues. 7 TR 1557. This, in turn, led to corresponding adjustments to test year revenues and revenue requirements. See 5 TR 618, 7 TR 1287; see also Exhibits A-71 (modifies Exhibit A-10) and Exhibit A-72. No party took issue with the Company's adjustment, and it should be adopted.

4. Depreciation and Amortization Expense

Ms. Rogus testified:

> The Company used the Commission approved depreciation rates from the Case No. U-17653 Depreciation Case Settlement, along with the projected capital expenditures and assumed plant retirements, in the determination of this depreciation expense adjustment necessary to arrive at an appropriate level of book depreciation expense. Book depreciation expense was developed by applying the functional composite book depreciation rates to the average Projected Test Year depreciable plant balances. The adjustment on line increases depreciation expense from the historical period due to significant new investment combined with the higher book rates resulting from the Case No. U-17653 Depreciation Case Settlement.
> 5 TR 611

The Company revised its proposed depreciation expense based on adjustments that arose while this case was pending. 5 TR 627-629. Pursuant to those adjustments, the

Company set its total depreciation expense at $590.760 million, and the jurisdictional depreciation expense at $588.155. See Initial Brief, Appendix C, pg. 1, line 7. Staff proposes a depreciation expense of $586.138 million, based on a $41.988 million adjustment to various components of the Company's O&M expenses. 8 TR 2522.

5. Taxes

The Company projected its property tax expense for the test year at $168.8 million, and Mr. VanBlarcum provided the methodology used to arrive at that amount. 8 TR 1852-1855; Exhibit A-58. No party took issue with the Company's projected property tax expenses, and it should be adopted.

The Company projects Real and Personal Property Tax expense in the jurisdictional amount of $167,744,000; General Tax expense in the jurisdictional amount of $28,781,000; Local Income Tax expense in the jurisdictional amount of $1,130,000; Michigan Corporate Income Tax (MCIT) expense in the jurisdictional amount of $37,218,000; and Federal Income Tax (FIT) expense in the jurisdictional amount of $134,031,000. Initial Brief, Appendix C, page 1; Exhibit A-112. Ms. Rogus testified to the adjustments that were incorporated into projecting these expenses. 5 TR-627-629.

Staff agrees with the projection for general tax expenses, and local income tax expenses. See Initial Brief, pg. 118. Staff proposes a $3.833 million upward adjustment to the MCIT expense, which would set it at $40.481 million, based on various proposed adjustments to projected revenues and expenses. Id. Similarly, Staff recommends a $20.2017 upward adjustment of the FIT Expense, which would set it at $151.790 million, based on various adjustments to the Company's projected revenues and expenses. Id. Staff's FIT projection includes a $790,000 error it detected in the initial filing, which the Company does not dispute. See 5 TR 628, 8 TR 2540–2541.

6. Allowance for Funds Used During Construction (AFDUC)

This expense applies to projects with on-site construction activities of more than six months duration and an estimated plant cost (excluding AFUDC) in excess of $50,000. 5 TR 612. The Company projects a test year jurisdictional AFUDC amount of $5.663 million. Appendix C, page 1, line 15. Staff did not recommend any adjustments to the Company's proposed AFUDC amount. See Exhibit S-3, Schedule C1. Therefore, the Company's AFDUC projection should be adopted.

7. Calculation of Adjusted Net Operating Income

Based on the foregoing, it is proposed the Company's total projected net operating income for the test year be set at $536,000,000. See Appendix C.

VII. OTHER REVENUE AND ACCOUNTING ISSUES

A. Revenue Adjustment Mechanism

The Company characterizes its proposed Revenue Adjustment Mechanism as a means to consistently collect revenues authorized by the Commission in light of factors that make that effort difficult. The implementation of the mechanism would be dependent on the enactment of authorizing legislation during the pendency of this case. Ms. Collins testified to the proposal:

> The Company is proposing a symmetrical Revenue Adjustment Mechanism that compares the nonfuel rate revenues approved by the Commission in the most recent proceeding to the nonfuel revenue generated through actual sales for the period of time under evaluation. This comparison will be performed by rate class. The Company proposes to compare actual total delivery revenues (less customer charges) to the approved rate case delivery revenues (less customer charges), which

> would apply to all customers, and to compare actual nonfuel power supply revenues to the approved power supply revenues, which would apply only to Full Service customers. The difference in revenues would be deferred on the Company's books, pending an annual reconciliation process. The Company proposes that the revenues be reconciled on an annual basis, beginning with the end of test-year period in this case. If the Company collects more total delivery or total nonfuel power supply revenue during the 12-month period than was authorized by the Commission in this electric rate case, then following Commission review and approval, the Company would refund the amount of the over-collection to its customers on a prospective basis. Over-collected delivery revenues would be refunded to all customers, while the amount of over-collected nonfuel power supply revenues would be refunded to Full Service customers. If the Company did not collect its level of authorized delivery or nonfuel power supply revenues, then following Commission review and approval, the Company would collect the shortfall with approval of the Commission on a prospective basis.
> 7 TR 1327.

The reconciliation process, which would involve actual revenues, Ms. Collins referenced would be filed within 90 days of the end of the effective period, and the Company requests it be completed within 270-days to ensure compliance with accounting rules concerning the reconciliation of all revenues within 24 months of being realized. 7 TR 1328-1329; See also Exhibit A-28.

Staff characterizes the Revenue Adjustment Mechanism as a decoupling mechanism, which cannot be utilized by an electric utility. [32] Therefore, Staff, along with ABATE, Hemlock, Kroger, and the Attorney General, seeks the denial of the Company's request. All of these parties are correct, the Commission lacks the authority to approve a decoupling mechanism. See *In re Detroit Edison Co*, 296 Mich App 101, 110; 817 NW2d 630 (2012); see also *Enbridge Energy Ltd. Partnership v Upper Peninsula Power*

[32] As noted by Mr. Townsend, the Company's proposal meets the definition of a decoupling mechanism: a rate adjustment mechanism that separates fixed cost recovery from the amount of energy sold. 8 TR 2395.

Co., 313 Mich App, 669, 677-678; 884 NW2d 581 (2015). Absent that authority, the request for the proposed Revenue Decoupling Mechanism must be denied.

The request for approval conditioned on the enactment of legislation authorizing a revenue decoupling mechanism for electric utilities raises two concerns. First, whether such legislation will be enacted while this case is pending is unknown. Second, and more importantly, the content of what will ultimately be enacted is unknown, meaning what is conditionally approved in this case may not comport with the enabling legislation. For these reasons, conditional approval of a Revenue Adjustment Mechanism is not appropriate. If it comes to pass that such a mechanism can be authorized at some future point, the Company may seek approval of a one, interested parties may weigh in on the proposal, and the Commission can review and ultimately decide whether the proposal is warranted under the controlling legal authority.

B. Investment Recovery Mechanism

In its Application, the Company sought authorization to implement an Investment Recovery Mechanism (IRM) that would allow "for the recovery of the Company's incremental 2017, 2018, and 2019 capital investments, beyond investments incorporated in rates through the end of August 2017, associated with specific Distribution, Generation, and Environmental Compliance programs." 5 TR 680. Recovery for the investments would be through a surcharge effective on September 1, 2017, and in effect until rates are reset, with a reconciliation process at the end of 2017, 2018, and 2019. The Company provided projected incremental revenue requirements for each program for September 2017-2019, which is the sum of incremental return on investment, depreciation, property tax, and offset for AFUDC, along with the source of the calculations. Exhibit A-68; 5 TR 681-684. The proposed reconciliation process is similar to what the Commission approved for DTE Gas in U-16999, and what the Company is proposing in its pending gas rate case, U-17882. 5 TR 684-685. The Company also provided a hypothetical reconciliation, which Mr. Torrey testified would safeguard against imprudent investments. Exhibit A-69; 5 TR 684-687. By allowing recovery "actual, prudent capital investments as authorized by the Commission", the IRM would reduce regulatory lag, and likely extend the period between the Company's general rate cases. 5 TR 687.

Staff notes the Company's IRM is "nearly identical in operation…" to what it proposed, and the Commission rejected, in U-17735. 8 TR 2588. As in that case, Mr. Lawure testified the proposal "still fails to meet the test year requirements of MCL 460.6a(1), does not provide adequate review of future expenditures for reasonableness and prudence, and does not account for the cost reductions which will undoubtedly occur if the investments were to occur and operate…." 8 TR 2588-2589. Thus Staff requests the Commission not approve the proposed IRM.

Staff determined an IRM that is "significantly scaled down…" could benefit both the Company and ratepayers, provided it operated in a manner that addressed the concerns over the use of a projected test year, effective prudency review, and accounted for cost reductions. Id., 2589. To that end, Staff recommends an IRM that:

> [F]ocuses on only distribution capital and distribution operation and maintenance programs that either represent the legal obligations of the Company or promote system resiliency and operational efficiency. Staff's alternative varies in operation from the Company's in order to meet the requirements of MCL 460a(1) and the use of projected test years. To accomplish Staff's objectives, the alternative IRM will utilize the test year approved amounts in the instant case for the first iteration of the IRM (last four months 2017). Staff's alternative IRM will also require the Company

> file an annual plan case for parties to rate cases to review and approve prior to the Company instituting the surcharge each year. The company's annual plan would serve as the basis for the annual reconciliation of the surcharge which would allow parties to rate cases to review the necessity and prudency of the Company's proposed projects prior to approval each year. Finally, the IRM will contain an annual O&M offset for the annual benefits projected to be achieved from modernizations to the distribution system. Staff's alternative IRM will ensure that the benefits achieved through the IRM are transparent and accrue to the customers.
> 8 TR 2589-2590.

The 8 programs Staff proposes to include in its IRM, all of which fall under Distribution Capital and O&M, are all beyond the Company's control, New Business, Demand Failures, Asset Relocation, and Storm Restoration, or contribute to reduced costs by reducing outages, Vegetation Management, Grid Modernization, and Distribution Inspection. 8 TR 2590. Mr. Laruwe identified the significant cost savings to ratepayers that would result from including these programs, primarily by increasing the efficiency of the Company's distribution system. Id., 2591-2592.

Staff's proposed IRM's reconciliation would track the process the Commission approved for DTE Gas in U-16999:

> [F]or each year of the IRM's operation, the Company provide a planning report outlining projects and costs that constitute the spending plans along with other metrics that provide transparency into the operation and outline expectations for each program during the IRM year. The Company will then file a reconciliation after the conclusion of the IRM year comparing projects, costs, and metrics outlined in the plan filing in order to determine the reasonable amount of cost recovery from rate payers in the prior year. [33]
> 8 TR 2593.

The Company, while not conceding its proposed IRM is in any respect legally insufficient and/or unreasonable, accepts Staff's recommendation that it be denied. 5 TR 690. The Company also seeks the denial of Staff's proposed IRM, but agrees the

[33] The metrics used in this reconciliation process would be developed through a collaboration with the parties to this case.

approach embodied in it is a “starting point”, and could be acceptable with the certain modifications. First, the Company accepts the 8 programs identified by Staff have the greatest impact in reducing costs associated with outages, which means the removal of programs under Generation and Environmental. Mr. Torrey testified the Reliability and Capacity programs under Distribution were not included in Staff’s modified IRM, since they also meet the criteria Mr. Laruwe identified, so the Company proposes including both in the IRM. 6 TR 1174-1175. The Company also agrees with Staff’s proposal to an offset to investment costs for any cost reductions directly related to capital investment infrastructure projects and programs, such as AMI. However, it cannot agree to “one-way trackers” for a significant portion of its annual other O&M expenses in the manner envisioned by Staff. Exhibit A-116. Mr. Bordine explained this proposal would:

> [S]everely limit the Company management’s ability to react to unforeseen, unplanned, and emergent items which may arise from extreme weather, equipment failures, or new regulatory requirements without impacting customers. This proposal would constrain the Company’s ability to recover costs related to other emergent needs like corrective maintenance, streetlight repairs, staking costs, major equipment repairs, training requirements, new regulations, and needed technology upgrades. This would also affect needed funding flexibility for emergent O&M costs related to expenses sponsored by other Company witnesses for example, generation, environmental, and Information Technology expenses. Additionally, I am concerned with Staff’s inclusion of “Distribution Inspection” programs. The Company does not track its inspection activities in a specific programmatic manner that would allow for repeatable, reliable reporting. Inspections are conducted under numerous programs and are done under the normal course of business in some cases.
> 6 TR 1176.

Accordingly, the Company objects to Staff’s recommendation of including “one-way trackers” for O&M expenses in the IRM. In regards to the reconciliation process proposed by Staff, the Company is willing to work through a collaborative to establish reasonable and appropriate metrics for the IRM planning and reconciliation process. 5 TR 695. The Company also agrees to Staff's plan filing and 90-day reconciliation proposal.

The Attorney General, ABATE, Wal-Mart, Hemlock, MEC, and Kroger all object to authorization of an IRM on legal and policy grounds. In regards to the latter, in U-17735 the Commission held that "policy considerations alone necessitates a decision declining to adopt…" an IRM that is the functional equivalent of what the Company proposed in this case. Case No. U-17735, November 19, 2015 Order, pg. 87. While it did not reach the legal issue, the Commission indicated the U-17735 IRM "appears to constitute a substantial single-issue rate case addressing a future period, without the benefit of accounting for cost reductions which will undoubtedly have occurred, or the benefit of reviewing expenditures for reasonableness and prudence." Id. However, Staff's proposal addresses those constraints by: setting IRM spending based on the test year spending levels set in this case; requiring the filing of annual plan that identifies projects/spending in the programs covered by the IRM, and reporting requirements that measure cost reductions from that spending, that must be approved before the surcharge is implemented; a reconciliation process that reviews the projects, costs, and metrics in the annual plan to set the reasonable amount of recovery. 8 TR 2589-2595; Exhibit A-115. Taken together, these measures render Staff's IRM compliant with MCL 460.6a(1) and MCL 460.6a(2). See *In re Michigan Consolidated Gas Company*, unpublished opinion per curium of the Court of Appeals, issued December 11, 2014 (Docket No. 316141), which affirmed the Commission's approval of an Infrastructure Recovery Mechanism in U-16999. The Court of Appeals found the mechanism did not set rates beyond the 12-month period in contrivance of MCL 460.6a(1), or constitute an automatic rate adjustment without a full and complete hearing in contrivance of MCL 460.6a(2). Mr. Laruwe testified Staff's IRM tracks the one approved by the Commission in U-16999. 8 TR 2593. See also Exhibit A-115. In considering both mechanisms, the characterization is accurate. Accordingly, the Commission has the authority to approve Staff's IRM.

Turning to the merits of Staff's IRM, Mr. Laruwe testified the 8 covered programs are reactive or present the greatest opportunity to reduce costs by enhancing system reliability. 8 TR 2590. Staff tied the programs together because when the costs of the reactive programs, which are difficult to predict because they are driven by factors beyond the Company's control, increase, a corresponding spending reduction is made in the proactive programs. Exhibit S-9.0. This, in turn, leads to decreased system reliability and increased costs. Mr. Laruwe illustrated this phenomena through the 400% cost increase over the past 10 years under Demand Failures. 8 TR 2591, Chart 1. Full funding and effective management of the Company's Vegetation Management and Distribution Inspection Programs will result in reduced costs, and a corresponding significant savings to ratepayers, by limiting emergency replacement of equipment due to storms or insufficient maintenance. Id., 2591-2592. Mr. Laruwe included Grid Modernization, a proactive program, in Staff's IRM because the benefits of the approximately $325 million in AMI spending will begin being realized in 2017. To fully realize those benefits, reduced costs through leveraging the data for efficient design and operation of the distribution system, it is imperative the Company fully fund and effectively manage the program. Id., 2592. Based on the foregoing, Staff's IRM should be approved because the 8 programs it proposes to be covered by the mechanism will, if fully funded and properly managed, provide the greatest opportunity to reduce costs and provide savings to ratepayers.

The Company requests two other programs, Reliability and Capacity, be included in Staff's IRM because they also provide benefits to ratepayers by enhancing system resiliency and operational efficiencies. 6 TR 1174-1175. However, most any operational program is, to some extent, intended to achieve those results. The issue is whether the program is proactive and has been inadequately funded because of reallocation to reactive programs. As for the Capacity program, Mr. Bordine testified the Company has a backlog of projects because of prioritization of other projects, but they do not appear to provide the benefit of significantly reducing costs, but rather as a component of service to HVD customers. Id. Conversely, the Reliability program projects, the upgrading of deteriorated equipment and reducing outages due to weather events, serve the intended purpose of the IRM, fully funding and properly managing programs that provide the greatest opportunity to reduce costs and provide savings to ratepayers. Accordingly, the Reliability program should be included in Staff's IRM.

The Company also objects to Staff's proposal to utilize an O&M offset in its IRM. The Company contends this component is essentially a "one-way" O&M tracking mechanism that would diminish its ability to react to emergent situations, and thereby impact its customers. 6 TR 1176. However, this argument goes to the very purpose of the IRM, and the reason Staff is now proposing its adoption: eliminate the shifting of funds from programs that, if fully funded and effectively managed, would result in savings to ratepayers. The example Mr. Laruwe used with the 400% increase in

Demand Failure spending over the past 10 years illustrates the viability of the O&M offset: if the Company fully funded the Vegetation Management and Distribution Inspection programs, which account for 25% and 18% of system outages respectively, at their approved levels, that increase would have been significantly reduced. 8 TR 2591-2592. Without this offset, the purpose of the IRM, ensuring spending on the covered programs will correspond to what was approved by the Commission, would be eliminated. In the process, the benefit of the IRM, reduced costs attributable to the failure to fully fund the covered programs, would also be eliminated. For these reasons, the IRM should contain an annual O&M offset for the benefits projected to result from the modernization of the Company's distribution system.

Based on the foregoing, Staff's IRM, including the O&M offset and the Reliability program added to the 8 programs identified by Mr. Laruwe, should be adopted. 8 TR 2590, table 3.

The final issue is whether the approval of the IRM should have any effect on the ROE level. Staff and the other parties all contend the IRM reduces the Company's risk exposure, and increases it for ratepayers, and thus its approval is a proper consideration in adopting the ROE they are advancing. However, beyond the generality that the IRM reduces risk, the record is devoid of any evidence that quantifies the reduction, or allows for its quantification. Further, as Mr. Rao noted, a recovery mechanism has no effect on the Company's cash flow, liquidity, or cost of capital. 4 TR 246. Therefore, the IRM cannot, standing alone, provide a basis to accept or reject any of the ROEs proposed by the parties in this case. Rather, and as discussed above, Staff's proposed ROE of 10.0% should be adopted.

C. Accounting Requests

1. Deferred City Income Taxes

In the past, the Company's costs under this category were deemed immaterial and not tracked, and were accounted on a cash or accrued basis. 5 TR 743-744. However, the amount has reached a point where the Company now seeks accounting authority to prospectively record its deferred city income taxes and approval of an offset to deferred tax liabilities with those not previously recorded. Id., 743-747. The Company proposes to account for this liability under the GAAP deferral accounting method, which it also utilizes for its other tax liabilities, and is consistent with Commission holdings. Under the deferral method, the Company will record a one-time deferred income tax liability of $14 million as of December 31, 2015, and requests approval to recognize a regulatory tax asset as the offset. Id., 745.

The RCG objects to this request on a number of grounds, with the primary one being the claim the proposal constitutes retroactive ratemaking. In response, the Company agrees that retroactive ratemaking is unlawful, but contends this proposal for "approval to prospectively use deferred income tax accounting for city income taxes." Id., 747. The Company's authority for its contention that the proposal does not run afoul of the prohibition on retroactive ratemaking is:

> In *Attorney General v. Pub Serv Comm*, 262 Mich App 649; 686 NW2d 804 (2004), the Court of Appeals held that deferred accounting treatment of past expenses coupled with the amortization of the deferred amounts in future rates does not violate the rule against retroactive ratemaking. The Court of Appeals found that such deferred accounting treatment was consistent with the principle, stated in *ABATE v. Pub Serv Comm*, 208 Mich App 248; 261, 527 NW2d 533 (1994), that "when capitalized expenditures are amortized, the amortization becomes a current expense even though it reflects expenditures that were capitalized in the past." *Attorney General*, 262 Mich App at 656, 659. Therefore, the Court of

> Appeals found that such deferred accounting procedures were proper where the resulting rate order sets future rates (i.e. rates that will be charged in a future period of time) without readjustment of rates charged in prior years and where the expense deferral was consistent with "accepted regulatory and accounting principles." *Id*. at 658. The Court also held that it is irrelevant, for purposes of retroactive ratemaking analysis, whether the deferral of the expense is approved before or after the expense is incurred.
> Reply Brief, pg. 174.

Based on this authority, deferred accounting and ratemaking treatment is proper, provided it doesn't readjust rates charged in prior years and is consistent with regulatory and accounting principles. Based on Ms. Hesche's testimony, and given that the proposal is limited to rates charged in the future, the accounting request for Deferred City Income taxes in not retroactive ratemaking under the authority cited by the Company. Therefore, the RCG's arguments concerning this proposal should be rejected.

The test year impact of the change includes $438,000 (prior to application of the revenue multiplier) related to the amortization of the regulatory asset and $994,000 for deferred taxes on book/tax differences included in this case. Id., 746. In addition, the Company seeks:

> [A]pproval to record a one-time adjustment to deferred income tax liabilities of about $14 million and an associated regulatory asset of about $14 million ($9 million net of federal income tax effects). This one-time adjustment is based on the amount of city deferred taxes associated with book/tax differences as of December 31, 2015. Finally, the Commission should authorize the straight-line recovery of the regulatory tax asset over a 20-year period, the approximate period over which the associated book/tax differences will reverse.
> Id., 747.

Based on this record, the Company's request for the treatment of deferred city income taxes should be granted.

2. Coal Combustion Accounting Retirement

The federal Coal Combustion Residuals ("CCRs"), which covers coal ash, sets minimum standards for reusing and disposing of non-hazardous CCRs. Subsequently, the DEQ proposed using more prescriptive state standards should be established for certain categories of waste management facilities, and notified the EPA it intended to regulate these facilities. 7 TR 1550. In response to the DEQ's proposal, the Company projected an additional Asset Retirement Obligation ("ARO") of $68 million for coal ash disposal, which entailed $47 million for disposal and $21 million for ground water monitoring. Id.

The Company is requesting the same recovery that was approved for its existing AROs. 7 TR 1551. Asset retirement costs are recovered through cost of removal in depreciation rates, and the Company proposes that this new ARO be included in Consumers Energy's next electric depreciation case. 7 TR 1551. Additionally, the Company requests Commission establish a regulatory asset/liability in order to recognize the timing differences between the cost of removal included in depreciation rates compared to ARO accretion and depreciation expense recognized on the Company's books and to keep ARO accounting income statement neutral. 7 TR 1551. This is the same methodology that is used for Consumers Energy's other AROs.

None of the parties objected to this request, and it should be granted.

3. Classic 7 Remaining Inventory

In U-18048, the Company filed an accounting application requesting approval to record the remaining book value of the Classic Seven Remaining Inventory at the time of retirement as a regulatory asset. 7 TR 1552. In this case, the Company seeks to amortize the regulatory asset over a two-year period from the date of an order granting approval for recovery. The projected amortization cost included in the test year was addressed by Ms. Rogus. 5 TR 613-615; see also Exhibit A-8, Schedule C6.

The Commission approved the accounting application on May 20, 2016, holding the Company's proposed accounting treatment related to the inventory, parts, and equipment associated with the Classic Seven's retirement was reasonable. The Commission also held the inventory, parts, and equipment expenses associated with the Classic Seven retirement should be charged to cost of removal and instructed the Company to include the inventory, parts, and equipment expenses associated with the Classic Seven's retirement in its next electric depreciation case.

4. Revenue Adjustment Mechanism

To implement this proposed mechanism requires accounting approvals. See 7 TR 1549-1550. However, given the recommendation that the request for a RAM be denied, these approvals are moot.

D. Line Loss

The MEC-NRDC-SC do not contest the recovery in rates of the Company's grid modernization expenses. See Initial Brief, pg. 82; Exhibit A-16. However, they make, through the testimony of Mr. Jester, two recommendations concerning those expenditures. First, the Company should be making "specific efforts to reduce line losses in its distribution system…", and "adopting dynamic volt-VAR control and the practice Conservation Voltage Reduction", which can be "greatly facilitated by using data from…" AMI meters. 8 TR 2189-2190. Second, the Company should be required to report the actual costs and benefits of the grid modernization expenditures, and reflect the results in the PSCR line loss factor. Id., 2190.

Currently, the Company expects its grid modernization programs will result in 1% reduction in system losses. Exhibit SC-9. However, Mr. Jester opines energy losses can be further reduced:

> The most cost-effective way to address this issue is to do so holistically, as part of a large-scale distribution capital spending program if one is in process. Therefore, when asking the Commission for approval to rate base a large amount of distribution capital spending, Consumers Energy should be expected to demonstrate that it will exercise appropriate diligence in ensuring that the combined costs of system losses and available mitigation measures have been or are being minimized. It is highly likely that such measures will be less expensive in context of other work on the distribution system and therefore that more such measures will be cost-effective.
> 8 TR 2233.

Mr. Jester identified 8 practices that he contends will mitigate system losses, and they should be examined, or required to maximize the benefits from AMI. Id., 2333-234. Mr. Jester also provided testimony on how these practices, in conjunction with a fully functioning AMI system, can reduce energy losses. Id., 2235-2248. Accordingly, Mr. Jester recommends that whatever rate relief is allowed in this case be conditioned on the Company submitting:

> [A] comprehensive plan and report covering these practices to the Commission by date certain and before or concurrent with its next filing of a general rate case or a request for Certificate of Necessity for new generation. I suggest that the date certain deadline for such report be 180 days after the Commission enters its order in this case. I further note that once implemented these practices should measurably reduce Consumers Energy's peak demand forecasts, energy sales forecast, and line loss factor and the Commission should expect future filings to reflect those effects.
> 8 TR 2248.

In response, the Company contends Mr. Jester's recommendations are unclear, unnecessary and/or premature. Further, the Company asserts that the recommendations are not the most cost-effective means to address line losses. 6 TR 1189. Rather, the steps the Company employs to reduce energy losses span a number of programs beyond Grid Modernization are effective, and it would "take significant additional investment above and beyond what is currently being requested in this rate case to make even a small reduction in the overall line loss factor." Id., 1190. Mr. Bordine also notes that some of Mr. Jester's recommended practices are already being undertaken by the Company, and while they contribute to reduced energy losses, they cannot be economically justified on that basis alone. Id., 1190-1191. Finally, Mr. Bordine testified that AMI data, along with data from other sources, are utilized on a number of levels, until "the Company fully deploys AMI meters, completes more Grid Modernization deployments, and connects more of its operational systems, Mr. Jester's practices will require significant manual analysis." Id., 1191. Given that energy loss is inherent in any electric system, Mr. Bordine noted practical limits make pursuing the lowest level of line losses, which is in essence what Mr. Jester is advocating, uneconomical. Id., 1192. Mr. Jester did not provide any specifics regarding the practices he is recommending, particularly on the costs under a specific program, they are taken as advisory in nature.

The Company also contends the report Mr. Jester recommends be submitted is unnecessary because the Company performs an appropriate level of activities related to line loss evaluation and mitigation. The MEC-NRDC-SC notes it made a similar recommendation in the Company's last rate case. While the Commission declined to adopt the recommendation, it noted the importance of reducing energy waste and directed Staff to “engage with stakeholders on the process going forward to educate and enhance understanding of this complex issue.” U-17735, November 19, 2015 Order, pg. 93. Given that AMI meters/Grid Modernization have not been fully deployed or connected to the Company’s operational systems, the reporting of benefits is premature. Assumedly, the Commission’s directive regarding engagement with stakeholders is proceeding and is sufficiently addressing steps that can reduce energy waste. Finally, the Company’s objection to Mr. Jester’s recommendation that line losses be reviewed, and if necessary, adjusted in PSCR cases, is valid. As Mr. Bordine noted, a line of Commission orders declined to order that step. Id., 1193. This is consistent with the fact “the Company’s energy delivery system investments and expenditures are reviewed in the context of general rate cases, it follows that line losses which occur on the energy delivery system should continue to be an electric rate case issue and not a PSCR issue.” Id.

VIII. REVENUE DEFICIENCY CALCULATION

Based on the foregoing, it is determined the Company will experience a jurisdictional revenue deficiency of $106,564,000 for the test year ending August 31, 2017, and rate relief to remedy that deficiency is appropriate. See Appendix A.

IX. COST OF SERVICE

A. <u>Cost of Service</u>

1. <u>Production Cost Allocation</u>

a. The Company

Ms. Aponte testified a Cost of Service Study (COSS) by rate class "is a systematic classification, functionalization, and allocation of a utility's fixed and variable costs to serve." 5 TR 536. To that end, a COSS must identify and separate costs for the production and distribution of electricity into jurisdictional rate classes, and then ascertain the contribution to jurisdictional earnings from those classes. In this case, Ms. Aponte prepared two cost of service studies:

> The Test Year Electric COSS – Version 1 ("COSS Version 1") is at Exhibit A-11 (JCA-2), Schedule F-1. The COSS Version 1 uses a 75/0/25 weighting methodology (75% demand, 0% on-peak energy, and 25% total energy) for production capacity, and 4 coincident peaks ("CPs") for the demand component. 5 TR 543. The allocation methodologies used in the COSS Version 1 are the same as those used in the 2014 Historical Electric COSS. 5 TR 544. The Test Year Electric COSS – Version 2 ("COSS Version 2") is at Exhibit A-11 (JCA-3), Schedule F-1.1. The COSS Version 2 differs from the COSS Version 1 in two respects: (1) it proposes a change in the allocation schedules for production capacity; and (2) it proposes a change to the intersystem sales allocator. 5 TR 544.
> Initial Brief, pgs. 197-198.

Ms. Aponte provided the sources and basis for the underlying components of both studies, and indicated the allocation methodologies are the same that were approved in U-17735. 5 TR 537-543.

The Test Year COSS – Version 1, which incorporates the test year changes proposed by the Company in this case, "uses a 75/0/25 weighting methodology (75% demand, 0% on-peak energy, and 25% total energy) for production capacity expense, and 4 CP for the demand component." 5 TR 544; Exhibit A-11, Schedule F-1. The Test Year COSS – Version 2 uses a 100/0/0 weighting methodology and 4 CP for the demand component, and uses:

> Test Year COSS – Version 1 as its starting point and includes the following updates: a) change in the allocation schedules for production capacity; and b) change in the intersystem sales allocator. The Test Year COSS – Version 2 then unbundles the Company's proposed jurisdictional revenue requirement for rate design purposes, with a new breakdown of the General Unmetered Experimental Lighting Rate GU-XL ("Rate GU-XL") COSS.
> 5 TR 544.

Ms. Aponte testified the change in the weighted methodology for the production capacity expense to the 100% weighting in Version 2 is based on:

> The Company's capacity planning function is designed to reliably meet its customer demand requirements which, for Consumers Energy, is overwhelmingly set in the summer months. Because of this, allocating fixed capacity costs based upon each class' contribution to summer system peak demands provides a more straightforward reconciliation to cost causation principles versus the current practice of using customer energy profiles to partially allocate demand-based costs. The Company's 4CP100 proposal better aligns each customer class' assigned capacity cost recovery with the capacity costs actually incurred to serve each customer class.
> 5 TR 545.

Ms. Aponte asserts "allocating fixed capacity costs based upon each class' contribution to summer system peak demands provides a more straightforward reconciliation to cost causation principles versus the current practice of using customer energy profiles to partially allocate demand-based costs. 5 TR 545. The Residential class, primarily through air conditioning load, contributes "most significantly to summer peak and system capacity requirements." Id., 546. See also 4 TR 342-343; Exhibit A-12. Accordingly, the Company requests the Commission approve for the production capacity expense the allocation contained in its COSS Version 2: a 100/0/0 weighting methodology (100% demand, 0% on-peak energy, 0% total energy) with 4 CPs for the demand component. 5 TR 545. Under this method the Residential class would have an increase of $31 million in capacity costs, and the Secondary class would see a $5 million increase, while the Primary class' capacity costs would be reduced by $33 million. Ms. Aponte termed the increased costs for Residential and Primary classes as reasonable based on an analysis that utilized customer hourly load information from 2011 to 2014, and entailed the following methodology:

> For each year, after adding back line losses, minimum hourly demands for each customer class and total bundled loads were extracted from the load data and the highest minimum hourly demand was selected as a reasonable proxy of a baseload generation requirement. The highest minimum hourly demand proxy assumes baseload capacity would be sized to meet the highest minimum requirement, rather than the absolute minimum requirement. Then, the highest minimum hourly demand for the residential class was divided by the highest minimum hourly demand for total bundled loads.
> 5 TR 548

The analysis indicated that the Residential class used, on average, 45.0% of total baseload capacity for the 4 years studied. 5 TR 469. Thus the 4CP 100/0/0 Production Allocator most closely captures that use under the 44.3% it apportions for Residential Total Baseload Capacity under the 4CP 75/0/25 compared with the 42.6% apportionment under the 4CP 75/0/0 allocator. Id.

Certain of the Parties agree with the Company's proposed 4CP 100/0/0 production capacity allocator, with modifications, while others object and request the current 4 CP 75/0/25 method be retained.

b. Staff

Staff contends the current 4CP 75/0/25 allocator, which is weighted 75% based on demand and 25% based on energy use for the entire year, be maintained. Staff notes that while the production allocator has undergone certain discreet modifications over the years, the year-round energy weighting of 25% has remained in place. In this regard, it notes that on two occasions last year the Commission considered and rejected the 4CP 100/0/0 production allocator. Case No. U-177335, November 19, 2015 Order, pgs. 97-98. See also In re Consumers Energy, Case No. U-17688, June 30, 2015, Order, pgs. 12-17. [34]

Staff contends the Company's stated basis to accept its proposed production allocator is, for a number of reasons, flawed. For example, Ms. Aponte contends that energy weighting allocates fixed production costs to customers that have no direct relationship to how they are incurred, or how the underlying assets are used. Mr. Putman notes this contention is premised on the proposition that production assets are obtained solely to meet peak capacity demand. 8 TR 2683. However, Mr. Putman notes that in deciding to acquire these assets the Company must consider the need to meet demand both on the hottest day of the year, and its energy requirements for all 8,760 hours in a year. Id. Since both demand and energy are factors in the acquisition of production assets, they must both be factored into the allocation of the costs of the assets. Mr. Putman contends Ms. Aponte expressly acknowledged this by noting the "Company's Commission approved production capacity portfolio has been assembled to economically address the diversity of customer demand requirements throughout the year…." 5 TR 546. Thus, when the Company had to meet its peak load in 2014, 3,000 MW, or its typical minimum demand of 1,500 MW, it had to do in an economical manner

[34] Case No. U-17688 was in response to the enactment of Act 169 that required the Commission "examine cost allocation methods and rate design methods used to set rates…." MCL 460.11(3). In that case the Commission changed the Company's production allocation method from 4CP 50-25-25 to 4CP 75-0-25. The Commission set the same production allocation method for DTE Electric Company. See Case No. U-17689, June 15, Order, pg. 23.

that factored in both production and energy. 8 TR 2683-2684; Exhibit A-12. Staff contends that the Company's current production allocator of 4CP 75/0/25 reasonably represents both production and energy.

Staff also argues against changing the allocation of Intersystem Sales. Mr. Putman notes the Company has not provided any substantive basis to change from a capacity allocator to an energy allocator "to follow the nature of the transaction." 5 TR 549. Given the "significant impact on class revenue deficiencies…" by "shifting revenue responsibility between the jurisdictions and classes, Staff recommended the decision to change the allocator until its necessity has been fully supported." 8 TR 2684.

c. MEC/NRDC/SC

These parties also object to the Company's proposal noting it has, for the most part, raised the same arguments it offered in the past, that the Commission considered and rejected, regarding the production allocator. 8 TR 2175-2176. If the Commission is inclined to revisit the issue, Mr. Sansoucy recommended a method that he contends goes to the stated basis for the Company's proposed allocator: residential customers should bear the cost of peak demand during the summer months. Mr. Sansoucy notes this demand is met by the Company's peaking units, so consideration should be given to the Equivalent Peaker Method of production cost allocation:

> [T]he cost of peaking facilities should be allocated based on demand, because they are being used to meet peak demand requirements. According to the Equivalent Peaker Method, the fixed cost of baseload plant generation should include an allocation based on energy, because the incrementally higher fixed cost of that category of generation produces relatively lower energy costs, which provide value especially to higher load factor customers. Residential customers should bear an equitable share of the cost associated with peaking resources, but it is not consistent with

> cost causation to allocate the cost of baseload resources to them on the same percentage as the peaking resources used to meet peak demand. Therefore, it would be consistent with the Equivalent Peaker Method to allocate the fixed costs of peaking units using the 4CP 100-0-0 method, if and only if the fixed costs of baseload units were allocated using the 4CP 50-25-25 method that represents the default method under Act 169.
> 8 TR 2183; see also Exhibit MEC-24.

Based on the foregoing, the MEC contends the Equivalent Peaker Method properly allocates the fixed costs of baseload, at 4CP 50/25/25, and peaking assets, at 4CP 100/0/0.

Mr. Sansoucy also called into question the Company's contention that only residential customers drive peak summer demand, and thus should be allocated fixed production costs accordingly:

> Exhibit MEC-23 is a graph and table showing hourly demand by customer class on July 22, 2014, Consumers Energy's 2014 peak. This document was prepared from an attachment to discovery response 17990-MEC-CE-48, which is too voluminous to file with my testimony. In this exhibit, commercial and industrial demand peaks during the early to mid-afternoon, while residential demand ramps up as customers come home in the evening and then ramps down after a few hours as they go to bed. Consumers proposes to allocate the fixed cost of its entire production fleet based 100% upon residential customer demand for this hour and three others during coincident summer months – demand that Consumers will meet with the lower-fixed-cost peaking resources.
> 8 TR 2179-2180.

Along the same lines, Mr. Sansoucy noted the difficulty in ascertaining fixed production costs, specifically in regards to Mr. Ronk's testimony that "fixed costs associated with generation the company received via Power Purchase Agreements (PPAs) from variable costs associated with that generation. Mr. Ronk concludes that of the $2,061,741,000 of PSCR expense expected to be incurred during the test year, $681,357,000 or 33.0% is fixed expense." Id., 2176. Mr. Sansoucy notes, and the proceeds to establish, that under the Palisades PPA, the allocation of "fixed and variable costs is not representative of the true fixed and variable cost for that generation plant." Id., 2176-2178; Exhibits MEC-20, MEC-21, MEC-22. Mr. Sansoucy testified this exercise exemplifies the difficulty in ascertaining the actual fixed and variable costs associated with generation, even under a PPA that is intended to identify those costs.

d. Attorney General

The Attorney General also argues the Company's 4CP 100/0/0 production capacity allocator should be rejected, noting the Company and Intervenors who support the change have not presented any evidence or arguments that have not been addressed before. See 8 TR 2381. The Attorney General asserts that the rate allocation methodologies established in U-17335 reflect years of litigation, and are just and reasonable to all of the Company's ratepayers. In the event the Commission decides to revisit the issue, Mr. Coppola agreed with Mr. Sansoucy's Equivalent Peaker Method because it best reflects the cost causation principle. Id., 2382.

e. ABATE

ABATE supports the Company's proposed production capacity allocator, noting it better reflects actual planning and operational considerations that are absent in the annual energy usage component of the 4CP 75/0/25 method. In this regard, Mr. Phillips testified the Company's method takes into account the planning of, and investment in, fixed production necessary to reliably meet customer demand is based on summer peak demand. Since that demand is residential customers, the investment should be allocated accordingly. Further, the Company's proposal sends accurate price signals that reflects the costs associated with that demand, and results in competitive rates that attract energy-intensive customers. 8 TR 2010.

Mr. Phillips contends the 4CP 100/0/0 cost allocator is consistent with the fundamental purpose of establishing cost of service: determining and arranging costs according to major functions, such as production, transmission, and distribution; classifying the costs to determine if a variance results from factors such as demand upon the system, or number of customers served. Id., 2009. Conversely, utilizing an energy weighting component in the allocator is outdated, given its purpose is to capture the additional costs incurred in generation of lower cost energy, i.e. coal and nuclear power. With the current trend of generating with natural gas, which requires lower capital investment and fuel costs, classifying 25% of production investment "as energy related is no longer valid." Id., 2044. The 4CP 100/0/0 method also sends the proper price signals to customers, which has two benefits. First, it will cause them to reduce their demand, thereby avoiding the need for new generation capacity and helping alleviate capacity shortfalls. Id., 2044-2045. Second, it will allow the Company to attract and retain energy-intensive customers.

f. Kroger and Wal-Mart

Both Mr. Townsend and Mr. Chriss testified to their agreement with the Company's contention that its capacity planning is designed solely to meet summer peak loads, and the proposed 4CP 100/0/0 allocator reflects the proper class alignment of those costs with their cause. 8 TR 2398, 2439-2440. Accordingly, both Kroger and Wal-Mart recommends the Commission adopt that method.

g. Hemlock

Mr. Gorman testified the 4CP 100/0/0 method accurately allocates to rate classes the costs of production resources, and open market costs of production and energy.

Concomitantly, the method produces price signals that allow customers to make efficient consumption decisions, and allows the Company to effectively manage its cost of service. In support of the method, Mr. Gorman set out to determine the lowest cost and most economical resource available to meet customer demand:

> Currently, Consumers' resource alternatives for baseload and peaking facilities are based on natural gas-fired units. In a Confidential response to discovery request 17990-HSC-CE-202 (attached as Confidential Exhibit HSC-1 (MPG-1)), Consumers outlined its current costs for a gas combustion turbine ("CT") and a natural gas combined cycle ("CC") unit. Without divulging Consumers' actual numbers, the relative trade-off for demand cost and energy cost is very clear. CC units' capital costs or demand costs are approximately 30% greater than the demand costs for a CT. However, the operating or energy cost for a CC is 20% to 25% lower than the CT operating cost.
> 8 TR 2076-2077.

Mr. Gorman testified these production resources costs reveals a relationship between capacity cost and energy cost, and it would be neither economical nor reflective of the Company's actual production costs to pay a higher capacity cost without a lower energy cost. Id. 2077. Mr. Gorman contends the 4CP 75/0/25 method has such a result, while the 4CP 100/0/0 method "reflects the economically rational relationship between Consumer's production capacity and energy cost in allocating costs across rate classes." Id. Mr. Gorman illustrated this relationship in a chart, based on data from the Company's COSS, that he contends indicates the current method results in an "illogical economic cost relationship between production capacity and energy costs." Id., 2078-2079. In addition to its economic validity, Mr. Gorman notes the 4CP 100/0/0 method most accurately reflects the competitive market prices, reflected by the MISO capacity market, of capacity and energy production costs by resulting in a uniform price per kW for all classes, and incorporating on-peak and off-peak usage. Id., 2080; Exhibit HSC-2.

Hemlock contends the Commission should revisit the 4CP 75/0/25 method, "in light of new evidence…" it presented through the testimony of Mr. Gorman that "has never before been presented to the Commission in a Consumers rate proceeding" and adopt the 4CP 100/0/0 demand production cost allocator. Initial Brief, pg. 4.

h. Recommended Production Cost Allocation

As acknowledged by the parties, the production cost allocation method has been litigated and considered by the Commission twice in the past 18 months. In the first case the Commission held "any cost allocation must, to some degree, reflect both demand and energy", and approved the 4CP 75/0/25 method "until such time as the Commission is persuaded that a different method better aligns Consumers' rates with cost causation." Case No. U-17688, June 30, 2015 Order, pg. 14. That time did not arrive by the second case, where the Commission again approved the 4CP 75/0/25 method, in part because "no change with respect to electric generation of production costs…" since the first case "support a change in the cost allocation method…." Case No. U-17735, November 16, 2015 Order, pg. 97.

While the Commission's holdings in U-17688 and U-17735 are not entirely dispositive on whether the production allocator should be changed, both decisions go to the proposition that year-round energy use is a proper factor in determining production costs. [35] In responding to contrary arguments, certain of which are again made in this case, the Commission discussed the two functions of capacity planning:

[35] The goal to accurately represent and allocate summer peak demand in production costs may be achieved through the Equivalent Peaker Method Mr. Sansoucy testified the Company should have considered. 8 TR 2180. The premise of the method, increases in peak demand are met by the addition of peaking capacity only, and intermediate and baseload units are properly considered energy-related, appears valid. Id., 2181; Exhibit MEC-24. Mr. Sansoucy provided a "rough and general estimate of costs" to illustrate the significance difference in costs for these various production assets used to meet baseload energy and peak demand requirements for the proposition they simply can't be uniformly allocated based 100% on demand. Id., 2181-2183.

> One function is identifying the total amount of capacity the Company needs to acquire to serve peak load. The other function is selecting the types of capacity needed to serve that peak load—as well as the differing loads on the system throughout the rest of the year—in the most cost-effective manner.
>
> It is important to remember that we are not allocating capacity, but the cost of that capacity. This is relevant because costs vary depending on the type of plant selected to provide an increment of capacity in the most cost effective way—given information about the number of hours the plant is expected to run (i.e., energy) throughout the year. It is, therefore, inappropriate to ignore the cost differentials between capacity types and allocate based purely on capacity.
> Case No. U-17688, June 30, 2015 Order, pg. 15-16, citing Staff's Reply Brief.

As Staff notes in this case, and consistent with those functions, the construction and acquisition of production assets is influenced by meeting demand, whether it is the hottest day of the year, or the energy requirements of any other day of the year, a point Ms. Aponte acknowledged. 5 TR 546. Since both demand and energy requirements factor into production costs, under the theory of causation the costs must be allocated accordingly. The 4CP 75/0/25 method does that, while the 4CP 100/0/0 method does not. Therefore, any contention that energy requirements play no role in production costs cannot be sustained.

Certain of the parties advanced arguments that are purported to be both new, and a proper basis to move energy requirements entirely out of the production allocator method. For example, ABATE contends the 4CP 75/0/25 method represents an old paradigm of additional capital costs for coal and nuclear generation. As the MEC notes, this contention ignores two facts:

> (a) combined cycle gas generation which serves a baseload-to-intermediate function is considerably more expensive than combustion turbine generation that serves peak loads [Exhibits MEC-24 and MEC-25; Exhibit HSC-1 (Confidential)]; and (b) Consumers continues to make large

> investments in and incur considerable fixed O&M expenses for its coal-fired generation [Exhibits A-44 and A-45], the costs of which will be recovered from customers based upon the approved production cost allocator.
> MEC Initial Brief, pg. 98

Hemlock's contention of the economic irrationality of the 4CP 75/0/25 method, premised on Mr. Gorman's conclusion it results in higher production costs for high load customers, is similarly unreliable. First, as the MEC notes, Mr. Gorman never identified where in the Company's COSS he obtained the values, nor is the calculation in the table at 8 TR 2078 purporting to show the production cost comparison for demand and energy under the two methods ever explained. Second, and as again as the MEC notes:

> [I]t is unclear from either the table or Mr. Gorman's explanation what he means when he says that "the rate classes are all allocated energy cost at approximately the same costs" or that energy costs are allocated "in a symmetrical manner." One can only presume that he means that the total cost that the industrial class pays for a larger amount of energy is roughly the same as the total cost that the residential class pays for a smaller amount of energy. But Mr. Gorman never explains why that is a relevant comparison. In the prior cases, the Commission has rejected very similar presentations by Mr. Gorman because the fundamental premise of his analysis – that energy costs are allocated to the classes on a system average basis – is just not accurate:
>
> Consumers, ABATE, and Hemlock further argue that because energy-intensive users pay a considerable amount for energy, they should not be required to pay as much of a share of fixed production costs because the allocation of fixed versus variable costs would be asymmetrical. As the Staff pointed out in DTE Electric's Act 169 proceeding and in this case, this purported asymmetry does not exist because energy-related costs are not charged based solely on average energy [Case No. U-17688, June 30, 2015 Order, pg. 16].
> MEC Initial Brief, pgs. 99-100.

Based on the foregoing, none of the contentions regarding the 4CP 100/0/0 production cost allocation method raised by the parties in this case can be sustained.

Rather, the current 4CP 75/0/25 production cost allocation method is, for the reasons identified by Mr. Putman and Mr. Sansoucy, the best means to ensure that rates are equal to the cost of service.

2. Intersystem Sales Allocator

The Company's COSS – Version 2 also includes a change to the intersystem sales allocator from capacity to energy. Ms. Aponte testified the "proposed allocator 100 – Energy at Generation assigns a portion of these credits to Non-Jurisdictional customers, resolving the existing mismatch between the allocation of sales and costs." 5 TR 549. As a result of the change, and based on the Company's projected revenue deficiency, the Residential and Secondary classes' revenue credits are reduced by $11 million and $2 million, respectively, while the Primary class revenue credit is increased by $8 million. Id.

Mr. Putman contends the Company has provided "scant support for the proposed change…" and a lack of information to determine if it is reasonable. 8 TR 2685. Given the "significant impact on class revenue deficiencies…" resulting from the "significant shifting of revenue responsibility between the jurisdictions and classes…" Staff recommends any decision be deferred until is necessity and reasonableness has been established. This recommendation is valid given the amounts involved, which the Company and Staff set at different amounts. [36] More importantly, "resolving the existing mismatch between the allocation of sales and costs" is insufficient evidence to

[36] While Ms. Aponte testified to the effect of the change on revenue credits, while Mr. Putman testified the change would increase "the Residential and Secondary classes' revenue deficiencies by $7.4 M and $1.4 M, respectively, and decreasing the Primary class' revenue deficiency by $6.8 M." 8 TR 2684.

determine the reasonableness of the proposed change. Therefore, the change to the Intersystem Sales allocator should be denied.

3. Uncollectable Account Expense Allocator

Currently, the Uncollectable Account Expense allocator (UAE) is premised "on historic data on actual uncollectable gross write-offs separated into electric residential and business customers." 5 TR 559. This data indicates the average residential gross write-offs…comprise 91% of all electric write-offs on a dollar basis…" over the past five years. Id.; A-73. Staff proposes an allocation based on class revenue requirements under the theory the UAE constitutes as a general cost of doing business and its proposal represents the nature of the expense:

> Uncollectibles are a result of certain customers not paying their bills. The amount of uncollectibles for any given class is a function of the number of customers within that class who do not pay their bills and the amounts of those bills. The customers in any class who pay their bills bear no more responsibility for those who do not than do the members of another class. Therefore, Staff has created Allocator 701, based on class revenue requirements. Revenue requirement represents the amounts that will be owed to the Company by customers as a result of rates set in this case, and is, by definition, a cost-based approach.
> 8 TR 2685-2686.

The Company notes that under Staff's proposal the residential class would only be allocated 45% of uncollectable costs, while the current method apportions 88% of the expense to the class where 91% of the expense originates. 5 TR 559. Further, Staff's revenue requirement allocator would assign uncollectable expenses to classes that "almost never default…" Id., 560. The Company is accurate when it notes that result would violate the principle of cost causation. Further, the current allocation is consistent with NARUC guidelines, which classifies uncollectable expenses as customer-related. Id. Accordingly, the current methodology of allocating based on average customers is appropriate, and Staff's proposed modification should be rejected.

4. Demand Response Allocator

The Company uses an allocator based on CWIP, which Staff proposes be changed to an overall allocation that uses total expenses functionalized to production as a base. 8 TR 2686. Staff contends this method is appropriate given that "demand response would affect many items in the COSS and developed overall Allocator 700, based on total expenses." Id. The Company agrees using that CWIP "is not the most appropriate…" method for this new allocator. 5 TR 560. However, instead of the new method proposed by Staff, the Company proposes using the existing revenue requirement Allocator 602. The Company's proposal produces a very similar result to the new allocator proposed by Staff's method. Id., 561. Therefore, the Demand Response allocator should be the revenue requirement allocator contained in Allocator 602.

5. Residential System Access Charge

Based on the results of its COSS, the Company proposes to increase its monthly system access charge for the Residential class from $7.00 per month to $7.75 per month. 7 TR 1312; Exhibit A-11. Staff opposes the increase, contending it is excessive because the use of customer-related costs was overbroad by virtue of including expenses for uncollectables, sales, customer administrative and general, general and common depreciation, and general and common property tax. 8 TR 2687. Mr. Putman testified that the Commission has long held not all customer-related costs should be recovered through this charge, but only those that vary with the number of customers, and are directly related to supplying service to customers. Id., 2688. Under Staff's methodology the costs are $6.00 per month, although Staff does not seek a change from the current $7.00 monthly charge. Id. The MEC agrees with Staff, and relies on the Commission holding in DTE's most recent rate case that rejected costs that it found did not vary the number customers on the system. Case No. U-17767, December 11, 2015 Order, pgs. 119-120.

The Company takes issue with the scope of the authority relied on by Mr. Putman, decisions from the 1970s, including one involving gas rates, by noting this charge was first approved by the Commission for the Company in 2008. In that case the Commission held "a flat customer charge . . . is a more appropriate way of collecting the fixed costs associated with serving each residential customer at any usage level." Case No. U-15245, June 10, 2008 Order, pg. 74. Subsequently, the Commission approved an increase and noted "the system access charge should likewise better reflect actual costs." Case No. U-16794, June 7, 2012 Order, pg. 111. To that end, the Company contends its system access charge is cost based, while Staff's approach removes charges that for customer-related functions and services that arise from customers connecting to the system. 5 TR 562. The Company contends the holding in U-17767 does not control because it is not apparent that the costs DTE proposed in its customer charge are the same as it is including in this case. This is valid, given that the MEC does not identify any costs in that case that are at issue in this case. Rather, it relies on the principle, only marginal costs of customer attachment can be recovered through the system access charge, instead of identifying costs in the Company's proposal that do not comply with that principle.

In considering the functions, the Company's contention that the costs it incurs are for workers performing customer-related functions that arise from, and vary with, customers connecting to the system is valid. For example, the number of residential customers has a direct bearing the Company's uncollectable expenses, meaning the expenses are marginal and should be recovered through the system access charge. Further, the record is devoid of any substantive evidence that the expenses for the other functions identified in Exhibit A-74 are not marginal, and thus properly recovered through the system access charge. Accordingly, those costs should be recovered through the $7.50 monthly system access charge, which was developed under the customer labor ratio that determines the customer-related expenses. Id.; Exhibit A-74.

Outside of the allocators, ABATE raised two issues with the Company's COSS that it seeks to have changed. First, ABATE contends the class loss factors contained in the demand and energy allocation factors be based on a three-year average loss factor, and not the 2013 loss study factors used by the Company. 8 TR 2086. However, the Company used the 2013 study because it is the most recent Commission-approved study, and was also utilized in determining total generation requirements. 5 TR 563. Further, the three-year average does not reflect the Company's efforts to reduce line losses, which are successful by virtue of the reduction in 2013, relative to the results in 2012 that would be included in ABATE's proposal. 5 TR 563. Because the line losses represented in the 2013 study were the most recent Commission approved examination of the issue, using that factor in the COSS is appropriate.

The second issue concerns using class peak in the Allocator 127 for GPD Voltage Level 1 calculation after combining the GPDV1 profile with the profile of the former General Service Large Industrial Economic Development Primary Rate E-1 Voltage Level 1. The Company agrees, but notes Mr. Gorman's 2012 class peak value is inaccurate because it mistakenly included the profile of Rate E-1 Voltage Level 2. 5 TR 563-564. The Company provided the appropriate class peaks, and it is recommended those values be used in calculating the Allocator 127 for GPDV1. 5 TR 564.

B. Rate Design

According to Ms. Collins, the Company's goal in rate design is to "1) establish rates that adhere to the cost of service as required by 2008 Public Act 286 ('PA 286'); 2) establish rates that promote efficient use of the Company's electric system and promote customer energy efficiency; 3) establish rates that promote a favorable business climate while meeting the other stated objectives; and 4) provide the Company with a fair opportunity to collect its revenue requirements." 7 TR 1305. Ms. Collins indicated the Company is proposing design changes for its Residential, Secondary, and Primary Rate Classes, and provided the specific changes and basis for the changes. 7 TR 1305-1323. Various parties object to aspects of the Company's proposed rate design.

1. Residential Rate RT

The Company proposes to close this rate, which provides a window for current customers on this rate to move to another rate option after the final AMI meter roll-out is complete, but before elimination of this rate is proposed in the next general rate case application. 7 TR 1315. Staff objects and recommends this rate remain open until the roll-out is complete. 8 TR 2661.

In seeking to close this rate, the Company notes Residential Dynamic Pricing Rates is available to all customers with AMI meters and offers time of use pricing, along with a critical peak pricing or critical peak rebate that is expected to provide future capacity resource and help lower costs for all customers. 7 TR 1335. Closing Rate RT to new business allows the customers that are currently on the rate adequate time to consider and move to another rate option before the rate is eliminated, and will help avoid future confusion in selecting a residential time of use rate. 7 TR 1335. These are all valid points, particularly avoiding future confusion, so the Company's proposal to close Residential Rate RT should be granted.

2. Residential Customer Charge

Based on their respective COSS, the Company seeks to increase this charge to $7.75 per month, while Staff contends it should be $7.00 per month. While maintaining its support of an increase, the Company agrees that if a different cost of service is ultimately adopted, the Company agrees that the customer charge should be adjusted accordingly so long as the charge is not reduced below the current $7.00 per month amount.

In comparing the COSS proffered by the Company and Staff, and in recognition of the rate changes that will ultimately result from this case, it is reasonable to leave this charge at the $7.00 per month currently embodied in the Company's rates.

3. Senior Citizen and RIA

The Company proposed to continue the Senior Citizen and RIA provisions offered under the RS and RT rate schedules and increase the Residential Income Assistance credit to $7.75 per month. 7 TR 1315. The Senior Citizen credit was also increased from $3.50 to $3.88 to maintain it at 50% of the monthly system access charge. 7 TR 1315. Staff recommends the monthly system access charge remain at $7.00 per month, meaning the RIA and Senior Citizen discounts also remain the same. 8 TR 2659. Based on the recommendation that the customer charge remain at $7.00 per month, the RIA and Senior Citizen provisions do not need to be changed.

4. Residential Electric Vehicle Rates (REV-1 and REV-2) and Dynamic Pricing Pilot Rates (RPD and RDPR).

The Company proposes the same basic rate design previously approved by Rates REV-1 and REV-2. The Company proposed changing the naming convention for the higher priced winter time period from "On-Peak-Winter" to a "Mid-Peak–Winter" descriptor to better reflect the time period within the context of the "On-Peak–Summer" pricing. 7 TR 1312. The Company also proposed to add "Mid-Peak-Winter" and "Off-Peak-Winter" time of use periods to mirror the winter time periods used in the Rate REV design. Id. Staff objected to changing the name of time periods because it could cause confusion and the current designation are properly descriptive. 8 TR 2703. The Company does not dispute this recommendation, so the name changes for time periods used across rates should not be changed.

The Company also proposes Rates RDP and RDPR as stand-alone rates, and thus removing the "pilot" designation. That request should be granted.

5. Direct Load Management Program/Peak Power Savers

The Company proposes changing the name of the pilot Direct Load Management Program to Peak Power Savers. In addition, the Company proposes the credits for allowing the Company to cycle participants' air conditioning off under the program be handled in the same manner as the interruptible credits for Rate GPD customers.

Assuming that the Company will qualify the Peak Power Savers Program as a MISO Load Modifying Resource, the Peak Power Savers capacity credits would be allocated to other customers based on the manner in which the test year COSS allocates total capacity costs. 7 TR 1314. In response to the Commission's Order in U-17735, the Company updated the calculations of Peak Power Savers credits. 7 TR 1313-1314. No party raised any objections to the Company's proposals regarding this program, and they should be adopted.

6. Joint Ownership Substation Credit

Hemlock recommends a change to the calculation of the Joint Ownership Substation Credit to allow customers that own their own substation and are transmission interconnected to receive a substation credit that offsets the Company's maximum demand charge. 8 TR 2096. As the Company notes, its proposed substation ownership credit serves both transmission and subtransmission voltages and is cost-based. Hemlock's proposal "would effectively eliminate the distribution charge for these customers." 7 TR 1339. This ignores the fact that the Company has to construct and maintain HVD at the 138kV level of service for all customers. 7 TR 1339. As these customers use the system, they should contribute to the associated costs. Therefore, Hemlock's proposal regarding this credit should be rejected.

7. GPD Rate Design

But for an update for its revised revenue requirement and price differentials, the Company did not propose changes to the basic rate design for GPD. 7 TR 1321. Hemlock and Kroger recommend a change to collect 85% of capacity charged through the On Demand charge for voltage level 1. This is an increase from the 75% of capacity costs collected through the On-Peak Demand charge the Company proposes, with remaining capacity costs through the energy charges, for all voltages. The Company utilized the same rate design for GPD as the Commission approved in U-17735, and objects to the proposed increase, noting it benefits high load factor customers on voltage level 1. 7 TR 1339. Mr. Townsend or Mr. Gorman did not provide sufficient basis to change the rate design for GPD. For example, Mr. Gorman contends the increase is revenue neutral. 8 TR 2090; Exhibit HSC-1. However, the Company notes that under the increase customers at a 50% load factor would pay 3% more than the Company's proposal and 6% more than the Company's proposal if they have a 90% load factor. This is not a revenue neutral proposal. Mr. Townsend contends the increase aligns rate design with causation. Id., 2399-2400. However, this is what the Commission did in U-17735, and what the Company is doing in proposing the same rate design in this case. Therefore, the Company's proposed rate design for GPD should be approved. [37]

The Company also proposes reinstating the On-Peak Demand ratchet that was previously utilized for customers that currently take service under Rate GPD. Ms. Collins testified the ratchet entails calculating On-Peak billing demand based on the highest on-peak demand created during the billing month but never less than 60% of the highest on-peak demand of the preceding billing months of June through September or less than 25 kW. 7 TR 1320. ABATE opposed the proposal because the Company has failed to establish a ratchet is necessary. 8 TR 2012. Given Ms. Collins' testimony that the ratchet "helps ensure that capacity costs are paid for by the customers for

[37] Staff's rate design for GPD set a capacity amount at slightly less than 75%, but it does not argue that its proposal be adopted over what the Commission approved in U-17735. See 7 TR 1337.

which capacity has been secured", and is necessary given the expected increase in capacity costs. 7 TR 1320. Accordingly, ABATE's objection to the ratchet cannot be sustained.

Hemlock and Kroger argue the ratchet should be rejected due to the fact that the Company did not estimate the additional billing units that would be produced. 8 TR 2097, 2401. The Company does not accept this contention, and notes it provided the information to Kroger through discovery. See A-87. However, the Company agrees that the final rate design approved in this case should include the additional billing units and revenue impacts associated with the Company's proposed mechanism. 7 TR 1340. The Company's proposal to reinstate an On-Peak Demand ratchet should be adopted, provided the measures Ms. Collins testified to concerning the objection of Hemlock and Kroger are utilized.

Finally, Mr. Gorman testified the term "Minimum On-Peak Billing Demand" was not defined on the Company's proposed GDP tariff. 8 TR 2098. However, the Company's proposed the tariff language, under the On-Peak Billing Demand section, defines the term as: "On-Peak Billing Demand shall never be less than 60% of the highest On-Peak Billing Demand of the preceding billing months of June through September, not less than 25 kW." 7 TR 1340; Exhibit A-11, Schedule 5, pg. 68. That description is both accurate and adequate.

Based on the foregoing, the Company's proposed rate design for GPD should be approved. 7 TR 1321.

8. Rate GSG-2

The Company did not initially did not propose changes to Rate GSG-2. Under that rate, GSG-2 customers would continue to pay the MISO LMP for energy at the Company's load node during the times they use stand-by service, and pay for capacity based on their demand when taking retail stand-by service. 7 TR 1310. ABATE contends GSG-2 demand charges were not reflective of the Company's cost to provide standby service to customers, and should reflect MISO Planning Resource Auction Clearing Price. 8 TR 2031-2032.

Ms. Collins testified to ABATE's request:

> There is no justification to allow Rate GSG-2 customers to pay capacity costs that do not reflect the utility's embedded cost of capacity. Consumers Energy is responsible for planning and securing capacity for all of its retail customers including customers served on standby rates. The cost of that capacity should be reflective of the Company's embedded cost of service as allocated to those customers in the Commission-approved Cost of Service Study used to establish rates. The charges for capacity under Rate GSG-2 were established prior to the MISO's capacity market and were based on the notion that if the Company had to secure additional capacity to service large standby load, the cost of that capacity should be passed onto the standby customer.
> 7 TR 1341.

The Company uses the historical demand for standby service customers in determining its capacity requirements, and thus it does not have to purchase additional capacity for those customers. Accordingly, the Company contends the MISO Planning Resource Auction Clearing Price has no bearing on this rate. Additionally, the MISO Auction Clearing Price is sold as an annual product, so the benefit of the price is based on the purchase for an entire year, not on a "per day" basis. 7 TR 1342. The Company argues its approach, combine standby and full customers' needs and charge all customers for capacity based on their expected use, is the most effective.

ABATE's proposal to set GSG-2 demand charges MISO Planning Resource Auction Clearing Price should be rejected because it would not reflect the Company's embedded cost of capacity. Further, the MISO Planning Resource Auction Clearing Price does not represent a per day cost, and thus has no bearing on the GSG-2 demand charges. Upon consideration of ABATE's proposal, the Company proposes to modify its Rate GSG-2 to reflect the approved embedded cost of capacity on a per kW basis, and provided an exemplar of that cost for secondary and primary customers. 7 TR 1341; Exhibit A-88. That modification is appropriate, and should be approved.

In addition, and in response to Staff's proposal, the Company seeks to modify the language of GSG-2 to clarify that the capacity costs are prorated for customers based on the actual number of on-peak days per month in which standby power was actually provided. 7 TR 1432; Exhibit A-85. Staff also proposes the Company's next rate case include a study that compares power supply revenue from GSG-2 customers and power supply costs associated with those customers. 8 TR 2713. Staff characterizes this study as a means to judge whether demand charges reflect the cost to serve standby customers. The Company notes this study is unnecessary given its participation in the Stand-by Rate working group convened under the Commission's directive. See Case No. U-17735, November 19, 2015 Order, pg. 111. Given a process concerning for the issues associated with stand-by service in on-going, requiring the Company to prepare a report on this issue, which it notes could be substantial, when it files a future rate case is duplicative.

9. Interclass Crossing Point Adjustment

To maintain the crossing points between Rates GPD and GP, the Company made an Interclass Crossing Point adjustment as part of its proposed rate design consistent with the Commission's holding in U-17735. 7 TR 1310. Staff request that in its next rate case, the Company should be required to bring Rates GP and GPD to their cost to serve without this adjustment. 8 TR 2673. The Company responds by contending such an adjustment is necessary when more than one rate is available to a class of customers. The adjustment represents an economic break-even point between the two rates, and without that point Ms. Collins testified to the possibility customers will migrate to the most economic rate:

> In order to maintain the crossing points, either dollars need to be shifted between the rate schedules or customers and kWh sales need to be shifted to reflect the rate that provides them the most economic benefit. This becomes an iterative process because moving customers from one rate to the other necessitates additional cost of service studies.
> 7 TR 1336-1337.

The Interclass Crossing Point adjustment will establish the breakeven point, and as the Commission held in U-17735, is reasonable. Therefore, the adjustment should be approved, and should not be precluded from approval in future rate cases.

10. Educational Institution Rates

Public and private schools, universities, and community colleges must be charged retail rates that reflect the actual cost of providing service. MCL 460.11(9). To that end, this rate splits educational institutions into their own class in order to determine their specific cost of service, and provides education credits within the rate design to discount the standard rate and reflect the entities actual cost of service. The Company also proposes to continue to provide this rate class a credit that removes the subsidies for RIA and Senior Citizens, which these customers are not required to pay. 7 TR 1324.

Except for the removal of the subsidies, Staff takes issue with the Company's rate design:

> The Company is essentially picking and choosing when to apply rates that reflect the cost to serve for education customers. Rates GS, GSD, and GP received a power supply and distribution credit; but when the result for Rates GPD and GPTU resulted in a higher power supply charge for education customers, the Company reverted back to including education customers with all of the other GPD and GPTU customers to avoid charging education institutions more than the standard rate. While the Company's intentions are good, this proposal does not comply with the law as written, which requires that public and private schools, universities, and community colleges are charged rates that reflect the actual cost of providing service to those customers.
> 8 TR 2670.

In order to meet the MCL 460.11(9) requirement:

> Staff proposes to establish Education Institution rates in the same manner as was performed in the Company's general electric rate case, Case U-17735. In that case, it was determined that Education Institution customers were not their own separate rate class and were charged rates that reflected cost to serve for each of the standard rates that Education Institution customers take service under. The fact that the results of splitting out the customers is so inconsistent shows that the customers are not served differently enough from those on the standard rates so as to merit a separate rate class. The method approved in U-17735 simply resulted in a credit on the distribution rates for Education Institution customers to remove the subsidies for Income Assistance and Senior Citizens, which these customers are not required to pay (Order, U-17735, Page 102).
> 8 TR 2670-2671.

The Company contends Staff's proposal effectively eliminates some customers from receiving lower rates:

> [T]o the extent that the cost of service shows that an educational customer class should receive lower power supply charges, the Company applied a credit to achieve the lower rate. This gets these customers classes to their cost to serve. In some rate schedules, the cost of service showed a higher

> cost to serve for the education class than for the rest of the class. Therefore, for these customers, only the distribution credit is applied which represents removal of low-income and senior subsidies.
> 7 TR 1335-1336.

This contention is accurate, Staff's proposal would result in some educational customers in paying higher rates, relative to other classes, in some rate schedules. Conversely, the Company's proposal to split the institutions in their own class, and then determine the cost of service and apply a credit if there is a cost benefit relative to the total rate schedule's cost of service, complies with the express language of MCL 460.11(9). Therefore the Company's proposed Educational Institution Service provision should be adopted.

C. <u>Other Tariff Issues</u>

For the tariff issues that are not rate-related, Ms. Rachel L. Brege summarized and explained the basis for the tariff issues that are not rate-related. See Exhibits A-20 and A-21, Schedule F5. Those issues that are disputed are addressed as follows.

1. <u>AMI Opt-out</u>

Consistent with the Commission's Order in U-17000, the Company provides an AMI opt-out option for its customers, with the charges for opting-out approved in U-17087, and again in U-17735. In this case, the Company proposes a modification to the opt-out charges to reflect the cost of service. The costs the Company is seeking to recover for opting-out of AMI generally include Up-front and Ongoing. See 7 TR 1436-1437. Since the benefit of the program accrues only to the participants in the program, they are assigned all associated costs.

In U-17087, which was filed in September of 2012, the Company projected 1.5% of its electric customers would participate in the program. Subsequently, and based on actual participation levels, the Company sets the opt-out participation level at 0.6% of its electric customers. Id., 1439. Based on that level, the cost per customer has been adjusted. Those costs are: one-time Up-front costs of either $163.82 for customers who retain their existing meters, or $219.48 to replace a smart meter with a legacy meter; and $19.43 per month for the cost of operations. See Exhibit A-65.

The RCG contends the Company failed to provide a substantive basis for both the initial and monthly surcharges, contrary to the Commission's directive in both U-17000 and U-17053. Absent this information, the RCG argues the charges for the AMI opt-out are unsubstantiated. The RCG also contends the Company's stated reason for the increased charges, lower AMI opt-out participation levels, should result in lower costs for meter readers and associated services. Along the same lines, the RCG argues the charges are excessive because the Company failed to properly incorporate the costs reductions achieved through its self-reporting of meters under R 460.115, and its budget plan. Under both programs, only one annual manual meter reading is necessary, meaning the costs for manual meter readings are significantly over-stated. If the meter reading aspects of both programs were properly reflected in the AMI opt-out, the RCG contends the costs for manual meter reads reflected in the monthly surcharge would be eliminated.

The RCG also contends participants in the AMI opt-out are paying for the costs of the program recovered through:

> [T]he greatly increased rate base associated with the AMI program, the rate of return granted to the utility on said rate base, and increased operation and maintenance expenses, higher property taxes imposed on the new meters and AMI infrastructure, and also greatly increased depreciation costs on the new AMI infrastructure and smart meters, including the depreciation costs recovered in rates applicable to existing

> undepreciated balances associated with wholly functioning existing meters which are being prematurely scrapped.
> Initial Brief, pg. 13

If these costs, along with the accelerated depreciation of AMI investments, were properly considered, the opt-out fees would be unnecessary.

Based on the foregoing, the RCG contends the record is devoid of evidence that would allow for the increased surcharges the Company is seeking for AMI opt-out customers. In fact, the RCG contends the charges should be completely eliminated because the Company failed to establish any net cost causation for opting-out of the program. In the alternative, the RCG seeks to have the surcharges adjusted to reflect the fact that only one annual meter reading is necessary for customers that self-read and participate in the budget plan.

The RCG also requests the Commission require the Company provide adequate advance notice that an AMI meter will be installed, and allow the installation only upon receipt of written permission of the property owner. The RCG characterizes the current notice the Company provides as lacking in information concerning the functions of an AMI meter, and the ability to opt-out of having a transmitting meter. Exhibit RCG-11. The RCG contends the inadequacy of the notice, coupled with not receiving written permission to install the device, is a contributing factor to the "unreasonably high and punitive opt-out surcharge" for having an analog meter reinstalled. Initial Brief, pg. 15.

Finally, the RCG raises a number of arguments concerning the Commission's lack of jurisdiction to mandate the installation of AMI meters and impose a surcharge for opting-out of the program. The RCG also contends the Commission has failed to conduct a contested case hearing to ascertain the health and safety implications of the devices, or consider the constitutional issues that surround their installation and imposition of the charges to opt-out. Id., 15-27.

The sufficiency of the Company's proofs regarding its proposal to increase the opt-out charges is addressed below. As for the RCG's other arguments, Mr. Warriner testified to the notice the Company is providing to its customers of the impending installation of an AMI meter:

> The smart meter installation customer notification process begins with public outreach and advertisements in planned implementation areas at least six months prior to meters being scheduled for installation. Public outreach efforts include presentations to municipal and community organizations about the Smart Energy Program benefits, installation schedule, and process. In addition, billboards and digital media provide another source of general awareness to customers. Individual customers are mailed postcard notifications 30 days prior to the scheduled meter upgrade. The Company also mails individual letters to customers 14 days prior to their scheduled meter upgrade, detailing what to expect on the day of the upgrade and what to do if they have questions. Lastly, the Saturday before the week of the scheduled upgrade, an automated call is made to the customer, again notifying them of the scheduled upgrade and providing a toll free phone number for questions or to schedule an appointment, if desired. This multi-step communication process has been implemented to make customers aware of the Company's plan to install a smart meter at their location.
> 7 TR 1438-1439.

Based on this testimony, the notice the Company provides regarding the installation of an AMI meter goes well beyond Exhibit RCG-11, and is more than sufficient to inform customers of the nature of the program, including the ability to opt-out if they so choose. The RCG's contention that installation should only be completed after written consent of the customer is obtained was raised in the Company's last rate case. In response, the Commission held the AMI meter is now standard metering technology, and as part of requesting service the customer consents to a having a meter. Case No. U-17735, November 19, 2015 Order, pgs. 130-131; see also *Detroit Edison Company v Stenman*, 311 Mich App 367, 382; 875 NW2d 767 (2015). For that reason, the RCG's renewal of the argument that written consent should be a requirement before an AMI meter is installed should be rejected.

The Company contends the RCG's argument concerning the lack of jurisdiction to approve charges related to AMI meters, along with the health, safety, and privacy issues that purportedly arise from their use, constitute an improper collateral attack on prior decisions of both the Commission and courts. See Reply Brief, pgs. 203-209. The Company's contention is accurate given the crux of the RCG's argument is this case provides "persuasive grounds…to reexamine the procedural and jurisdictional grounds of the MPSC orders, and of the Courts…." RCG Initial Brief, pg. 17. This case cannot serve as the vehicle for the RCG to re-litigate Commission orders, and Court of Appeals decisions concerning those orders, that it may disagree with, and any attempt to do so must be rejected. Similarly, the RCG's constitutional arguments concerning AMI meters is a collateral attack on Commission orders, and Court of Appeals decisions concerning those orders that have expressly rejected these claims. See Case No. U-17735, November 19, 2015 Order, pg. 124; see also *Stenman*, 311 Mich App at 387-388; *In re Application of Detroit Edison Co to Implement Opt-Out Program*, unpublished opinion per curium of the Court of Appeals, issued February 19, 2015, (Docket No. 316728) pg. 8-9. For these reasons, the RCG's jurisdictional and constitutional arguments cannot be sustained.

Staff objects to the proposed Tariff changes, arguing they are premature, may inappropriately influence customers, not supported by the record, and fail to include the appropriate off-sets. 8 TR 2700. On the timing of the increased charges, Mr. Revere notes the roll-out is still in progress and the number of customers opting-out will necessarily change up and until full deployment. In regards to the influence of the proposed charges, including the revised customer participation level, Mr. Revere testified:

> The problem with forecasting opt-out participation is that the number of customers opting out is endogenous, or internally correlated to the charge. In other words, the charge can have an effect on how many people opt-out, which is not the intended consequence, and become a self-fulfilling prophecy; if the charge is set for a higher number of customers than the actual number who would choose to opt out, then customers may opt out because of the low cost that may not have otherwise. Conversely, if the forecast is fewer than the true number of opt-out participants, then the high charges will discourage customers from opting out and result in lower participation. 8 TR 2701.

In consideration of both factors, Staff recommends delaying any changes to the Tariff.

The Company argues Staff's contentions are inaccurate given the full deployment of the AMI meters will be completed by the end of the Test Year, making this case the only vehicle for the Commission to allow for recovery of the implementation costs of the opt-out, including the up-front charges. 7 TR 1444. A delay in updating the charges would also mean customers currently opting-out are not paying the full cost of up-front charges, but those who enroll after full deployment will. Id., 1144-1445. Assuming the increased costs in the Company's proposal are valid, which is addressed below, this contention is valid. There is simply no reason for any delay in changing the opt-out charges to match the costs the Company is incurring. Staff's contention that the change is premature because the opt-out level is not set is also belied by the actual data. As of January 25, 2016, the acceptance rate was 99.49%, where it has stabilized after never dropping below 99% since 2013. Id. 1436. Based on this data, the 0.6% opt-out rate which was used in calculating the Company's proposed opt-out tariff charges is conservative. For the purposes of this analysis, the contention the rate will undergo a significant change as deployment is completed in 2017 is not supported by the record. Therefore, Staff's contention the change to the charge is premature and will influence participation, and thus warrants a delay, is unfounded.

As far as the support for the proposed change, Mr. Warriner testified the Company utilized cost-of-service principles to calculate the charges, and his workpapers setting forth the components of the cost, in detail, were provided to the parties when this case was filed, and entered as Exhibit A-118. Id., 1436-1441, 1477; see also Exhibit A-65. Neither Staff nor the RCG presented any evidence that specific charges in the AMI tariff are inaccurate or do not represent the actual cost-of-service for the AMI opt-out program. Rather, both parties argue the costs are unsupported and unreasonable. For example, Mr. Revere testified the Company did not offer any evidence that current opt-out customers are, and future customers will be, randomly distributed to justify the proposed increase in meter reading costs. 8 TR 2702. In Exhibit A-118, the Company indicates it will utilize 21 full-time meter readers for the monthly reads of 10,800 non-transmitting meters it projects under the 0.6% non-participation rate. That is a reduction from the 35 meter readers it expected to utilize in Case No. U-17087, where the non-participation level was projected at 1.5%. 7 TR 1439. As of January 2016, the Company has 4,245 non-transmitting meters, and based on the trend it reasonably projects that number to reach 10,800 when the installation process in complete at the end of 2017. Mr. Warriner testified the expectation is those customers will be randomly distributed throughout the Company's service territory. Id. That expectation is not unreasonable, especially given that no evidence was offered that the distribution is, in fact, centralized. The RCG contends that meter reading costs would be reduced if opt-out customers did self-reads and enrolled in the budget program, both of which entail annual instead of monthly manual reads. However, Mr. Warriner testified that monthly manual reads is the most logical and reasonable assumption to use in calculating meter reading costs. 7 TR 1525. This approach makes sense given that the Company should plan to manually read over 10,000 meters every month, which it is obligated to do under R 460.113(1). In regards to RCG's contention that it is possible all opt-out customers may self-read and enroll in the budget program, the converse is also true, no opt-out customer may enroll in either program. Again, it is reasonable for the Company to proceed under the assumption that, based on a 0.6% non-participation level, it will have to manually read over 10,000 meters every month. If it should come to pass that participation in the programs cited by RCG results in a substantive decrease in the number of monthly manual meter reads, the monthly surcharge can be revisited. However, merely because those programs are offered is not, standing alone, a sufficient basis to find the Company will only have to read non-transmitting AMI meter once a year. [38]

Based on this record, the Company has provided a factual basis in support of the proposed charges for opting-out of the AMI program, and the proposed charges constitute the cost-of-service for providing the opt-out program. Exhibits A-65 and A-118.

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[38] The customer meter reading rule expressly allows the Company to "read meters on a regular basis." R 460.115. Thus, contrary to the RCG's argument, this program does not necessarily entail annual meter readings. The budget plan referenced by the RCG is assumedly the equal monthly billing program authorized in R 460.118, which is silent on the frequency of meter readings.

Finally, the off-set Mr. Revere testified to was a credit approved in U-17087 to account for the costs of AMI infrastructure that are embedded in base rates. Noting AMI infrastructure is a core component of its utility service, and the costs have been approved through a series of rate case, the Company requests the Commission reconsider that credit:

> Consumers Energy submits that allowing a small portion of the Company's customer base to evade payment for a portion of a Commission-approved investment such as AMI is poor ratemaking policy. The opt-out option is an extraordinary provision under which customers may choose to avoid receiving what is considered to be standard utility equipment, yet continue to receive electric utility service from Consumers Energy. Consumers Energy is willing to continue to offer this unusual option, per the Commission's request stated in Case No. U-17000, but the Company believes that customers choosing the extraordinary option of not receiving standard utility equipment should not be allowed to avoid paying for the costs of that equipment. Consumers Energy's electric utility service is simply not an ala carte menu of options from which customers should be permitted to pick and choose. AMI opt-out customers receive benefits of the AMI Program even if they are not currently paying for it, such as increased reliability, better economics, system efficiencies, reduced theft expense, decreased outage response times, and decreased need for capacity as those customers with AMI smart meters increasingly take advantage of time-of-use and other capacity-minimizing rate options. The platonic ideal of strict separation of AMI and opt-out customers is not a realistic expectation or principle going forward, nor is it fair to the vast majority of customers who do not opt out of receiving a smart meter. The opt-out tariff proposed by the Company in Exhibit A-65 (LDW-4) reflects this position and request.
> Initial Brief, pgs. 222-223.

On its face, the Company's argument is compelling given that the Smart Grid/AMI program will provide a number of benefits to ratepayers when it is fully operational and integrated into the Company's utility service. See 7 1417-1418, 1428, 1431-1435; Exhibit A-64. Those benefits will accrue to all ratepayers irrespective of whether they have a transmitting or non-transmitting meter. However, the Commission has deemed an offset for these costs for the small segment of the customers who opt-out of the program appropriate. Assuming that position remains unchanged, the offset was calculated to include meter reading and AMI costs included in the revenue requirements in this case. Id. 1449-1450; Exhibit A-119. The offset is a $3.60 monthly credit, up from the current $1.00 monthly credit set in U-17087, and is premised on the costs underlying the increase in the opt-out charge the Company is proposing. Exhibit A-120. Based on this record, it is proposed the increase in the opt-out tariff charges, and corresponding increase in the offset, be approved. Exhibits A-65 and A-120.

2. Emergency Electrical Procedures

The Company is seeking revisions to this Tariff to better align its actions during emergencies with its obligations under MISO. 8 TR 1845-1846. Mr. Sherman identified the "significant revisions" to this tariff as:

1. updating the existing "Short-Term Capacity Shortages" tasks to reflect MISO terminology for "Sudden or Unanticipated Frequency Events" and "Actual or Forecasted Generation Capacity Shortages,"
2. revising the steps that need to be taken under a "Sudden or Unanticipated Frequency Event" or an "Actual or Forecasted Generation Capacity Shortage,"
3. removing the existing "Long-Term Capacity" emergency steps, and
4. revising the existing Fuel Shortages steps.

8 TR 1846; See also Exhibit A-11.

Mr. Sherman provided the reasons behind the revisions, and no party has challenged this proposal. 8 TR 1847-1848. Therefore, the Company's proposal to revise its Emergency Electrical Procedures should be approved.

3. Experimental Residential PEV Charging Program

Initially, the Company proposed eliminating tariff language concerning a now expired program that reimbursed customers who purchased Electric Vehicle Supply Equipment. 5 TR 721. However, in response to the suggestions made by the MEC concerning the residential component of the proposed PEV Charging Infrastructure program, the Company now seeks to amend the language to allow for a $1,000 incentive for the purchase of a home charging station, or to the owner of a multi-family dwelling that installs a station in a common area. Id., 726; Exhibit A-85. Additional modifications to the tariff were made to address ChargePoint's suggestion the home charging station have the ability to communicate data and load management tools. 5 TR 725. As discussed, *supra*, it is recommended the entire PEV program be delayed until a Michigan Electric Vehicle Collaborative is established to develop a statewide plan to govern utility involvement in PEV Charging Infrastructure. If that step is instituted, the tariff should not be amended to address the $1,000 incentive for the purchase of a home charging station. Conversely, if the Commission approves the residential component of the PEV program, the tariff should be amended to reflect the incentive. Exhibit A-85. Irrespective of what step is taken, the language concerning the now-expired reimbursement program should be removed from the tariff.

X. CONCLUSION

Based on foregoing, it is recommended the Commission find the Company's total jurisdictional rate base for the projected test year ending on August 31, 2017 is $10,171,612,000, Appendix B; its overall rate of return is 5.27%, which includes a cost of common equity in the amount of 10.00%, Appendix D; its adjusted jurisdictional NOI for the test year is $536,441,000, Appendix C; and the rate base, approved overall rate of return, and adjusted NOI results in a jurisdictional revenue deficiency in the annual amount of $106,564,000, Appendix A. In recognition of that proposed revenue deficiency, it is recommended the Commission authorize the Company to increase its rates for electrical generation and distribution by that annual amount.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Dennis W. Mack

Dennis W. Mack
Administrative Law Judge

December 16, 2016
Lansing, Michigan

MICHIGAN PUBLIC SERVICE COMMISSION **Appendix A**

PFD

Consumers Energy Company

Computation of Electric Revenue Deficiency for

Test Year - August 2017

(000)

Line	Description	Source	Consumers Total Electric (Brief)	ALJ Adjustments	ALJ Projection	ALJ Jurisdictional
	(a)	(b)	(c)	(d)	(e)	(f)
1	Rate Base	Exh. S2, Sch. B1	$ 10,232,150	$ (14,969)	$ 10,217,181	$ 10,171,612
2	Adjusted Net Operating Income	Exh. S3, Sch. C1	504,342	30,269	534,611	536,441
3	Overall Rate of Return	L2 / L1	4.93%	0.30%	5.23%	5.27%
4	Required Rate of Return	Exh. S4, Sch. D1	6.18%	-0.29%	5.90%	5.90%
5	Income Required	L1 x L4	$ 632,649	$ (30,201)	$ 602,448	$ 599,762
6	Income Deficiency (Sufficiency)	L5 - L2	$ 128,308	$ (60,471)	$ 67,837	$ 63,321
7	Revenue Multiplier		1.6377	-	1.6377	1.6377
8	Revenue Deficiency (Sufficiency)	L6 x L7	$ 210,126	$ (99,031)	$ 111,095	$ 103,699
9	Demand Response Revenue Requirement	Exhibit: A-8 (AKR-61)	$ 2,890	$ -	$ 2,890	$ 2,866
10	PEV Revenue Requirement	Exhibit: A-53 (AKR-62)	$ 1,271	$ (1,271)	$ -	$ -
11	Total Revenue Deficiency		$ 214,287	$ (100,302)	$ 113,985	$ 106,564

MICHIGAN PUBLIC SERVICE COMMISSION **Appendix B**
PFD

Consumers Energy Company
Development of Rate Base for
Test Year - August 2017
(000)

Line	Description	Source	Consumers Total Electric (Brief)	ALJ Adjustments	ALJ Projection	ALJ Jurisdictional
	(a)	(b)	(c)	(d)	(e)	(f)
1	Plant In Service	Exh. S2, Sch. B2	$ 13,982,802	$ (27,535)	$ 13,955,267	$ 13,899,876
2	Plant Held For Future Use	Exh. S2, Sch. B2	5,193	-	5,193	5,152
3	Construction Work In Progress	Exh. S2, Sch. B2	372,061	(1,824)	370,237	367,821
4	Classic 7 Inventory	Exh. S2, Sch. B2	-	-	-	-
5	Total Utility Plant	Exh. S2, Sch. B2	$ 14,360,056	$ (29,359)	$ 14,330,697	$ 14,272,848
6	Less: Depreciation Reserve	Exh. S2, Sch. B3	4,912,536	(389)	4,912,147	4,894,929
7	Net Utility Plant		$ 9,447,520	$ (28,970)	$ 9,418,550	$ 9,377,919
8	Retainers & Customer Advances		(28,857)	-	(28,857)	(28,837)
9	Working Capital	Exh. S2, Sch. B4	813,487	14,000	827,487	822,529
10	Rate Base		$ 10,232,150	$ (14,969)	$ 10,217,181	$ 10,171,612

Consumers Energy Company
Projected Net Operating Income
Test Year - August 2017
(000)

Appendix C
PFD

		Revenue				Expenses								NOI		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
Line No.	Description (Witness)	Sales Revenue	Wholesale	Misc Revenue	Total	Power Supply Costs	Other O&M Expense	Depreciation & Amortization	R&PP Tax	Other General Taxes	Local Income Tax	Michigan Corporate Income Tax	Federal Income Tax	NOI	AFUDC	Adjusted NOI
	Company Filed (Initial Filing)															
1	Operating Income	$ 4,160,903	$ 25,842	$ 53,336	$ 4,240,081	$ 2,168,037	$ 607,269	$ 596,236	$ 168,800	$ 28,943	$ 1,128	$ 36,648	$ 131,773	$ 501,247	$ 5,700	$ 506,947
2	Company Adjustments	$ 3,135	$ -	$ 101	$ 3,236	$ -	$ 9,387	$ (5,476)	$ (580)	$ -	$ -	$ 501	$ 2,009	$ (2,605)	$ -	$ (2,605)
3	**Company (Brief)**	$ 4,164,038	$ 25,842	$ 53,437	$ 4,243,317	$ 2,168,037	$ 616,656	$ 590,760	$ 168,220	$ 28,943	$ 1,128	$ 37,149	$ 133,782	$ 498,642	$ 5,700	$ 504,342
	ALJ Adjustments															
4	Sales Revenue (DLA/Recalc)	441			441							27	145	269		269
5	Intersystem Sales Allocation	1,109	(1,109)		-							-	-	-		-
6	Electric Distribution						(12,100)					733	3,978	7,389		7,389
7												-	-	-		-
8	SERP						(2,422)					147	796	1,479		1,479
9	DC SERP						(239)					14	79	146		146
10	Active Healthcare/Insurance/LTD						(2,600)					158	855	1,588		1,588
11	Corporate - Economic Development						(3,000)					182	986	1,832		1,832
12	Uncollectibles						(2,200)					133	723	1,343		1,343
13	Incentive Compensation						(12,020)	(100)				734	3,985	7,401		7,401
14	Pension & OPEB (Discount Rate Update)						(14,000)					848	4,603	8,549		8,549
15												-	-	-		-
16	Depreciation: AMI Load Control Switch							(97)				6	32	59		59
17	Depreciation: Distribution (Capacity & Grid Mod)							(525)				32	173	321		321
18								-				-	-	-		-
19								-				-	-	-		-
20								-	-			-	-	-		-
21												-	-	-		-
22	Proforma Interest (Nichols)											16	88	(104)		(104)
23	Interest Synchronization (Nichols)	-	-	-	-	-	-	-	-	-	-	-	1	(1)	-	(1)
24	**Total Adjustments**	1,550	(1,109)	-	441	-	(48,581)	(722)	-	-	-	3,029	16,445	30,270	-	30,270
25	**ALJ Net Operating Income - Test Year**	4,165,588	24,733	53,437	4,243,758	2,168,037	568,075	590,038	168,220	28,943	1,128	40,178	150,227	528,912	5,700	534,612
26	**ALJ Jurisdictional NOI - Test Year**	4,165,589		53,387	4,218,976	2,146,990	565,113	587,385	167,739	28,778	1,117	40,320	150,756	530,778	5,663	536,441

MICHIGAN PUBLIC SERVICE COMMISSION **Appendix D**

PFD

Consumers Energy Company

Overall Rate of Return Summary

Recommended Capital Structure & Cost Rates

Line	Description	Source	13-Month Average (000)	% of Permanent Capital	% of Total Capital	Cost Rate	Weighted Cost Permanent Capital	Weighted Cost Total Capital	Weighted Cost of Debt	Weighted Cost Pretax Basis
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Long Term Debt	Ex. A-9 (AJD-1)	$ 5,385,046	46.80%	36.07%	4.87%	2.28%	1.7565%	1.7565%	1.7565%
2	Preferred Stock	Ex. A-9 (AJD-1)	37,315	0.32%	0.25%	4.50%	0.01%	0.0112%		0.0184%
3	Common Equity	Ex. A-9 (AJD-1)	6,083,847	52.87%	40.75%	10.00%	5.29%	4.0747%		6.6731%
4	Sub-total		$ 11,506,208	100.00%			7.58%			
5	Short Term Debt-Revolver	Ex. A-9 (AJD-1)	-		0.00%	0.00%		0.0000%	0.0000%	0.0000%
6	Short Term Debt	Ex. A-9 (AJD-1)	164,600		1.10%	2.47%		0.0272%	0.0272%	0.0272%
7	Customer Deposits	Ex. A-9 (AJD-1)	-		0.00%	0.00%		0.0000%	0.0000%	0.0000%
8	Deferred FIT	Ex. A-9 (AJD-1)	3,206,960		21.48%	0.00%		0.0000%		0.0000%
	Other Interest Bearing Accounts	Ex. A-9 (AJD-1)	-		0.00%	0.00%		0.0000%	0.0000%	0.0000%
	Deferred JDITC									
9	Long-term Debt Related	Ex. A-9 (AJD-1)	25,217		0.17%	4.87%		0.0082%	0.0082%	0.0082%
10	Preferred Related		0		0.00%	4.50%		0.0000%		0.0000%
11	Common Equity Related	Ex. A-9 (AJD-1)	27,639		0.19%	10.00%		0.0185%		0.0303%
12	Total Capitalization		$ 14,930,623		100.00%			5.8964%	1.79%	8.51%